BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110138-EI

MINIMUM FILING REQUIREMENTS

SECTION F – MISCELLANEOUS SCHEDULES
VOLUME ONE

COM ___
APA 1
ECR 16
GCL 1
RAD 1
SSC 1
ADM ___
OPC ___
CLK ___

GULF POWER

A SOUTHERN COMPANY

DOCUMENT NUMBER-DATE
04690 JUL -8 =
FPSC-COMMISSION CLERK

GULF POWER COMPANY

Docket No. 110138-EI
Minimum Filing Requirements

Index

F. Miscellaneous Schedules
Volume One

Schedule F-1

ANNUAL AND QUARTERLY REPORTS TO SHAREHOLDERS

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 110138-EI	EXPLANATION: Provide a copy of the most recent Annual Report to Shareholders and all subsequent Quarterly Reports. The company shall file all Quarterly and Annual Reports as they become available during the proceeding.	Type of Data Shown: ___Projected Test Year Ended 12/31/12 ___Prior Year Ended 12/31/11 X Historical Year Ended 12/31/10 Witness: R. S. Teel, C. J. Erickson

Line No.	
1	Gulf Power Company's 2010 Annual Report is attached.

Supporting Schedules:

Recap Schedules:

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**	

(This page intentionally left blank)

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

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

Gulf Power Company 2010 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 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 Real Estate Investments	2010 Private Equity	2009 Real Estate Investments	2009 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.

(This page intentionally left blank)

SELECTED FINANCIAL AND OPERATING DATA 2006-2010

Gulf Power Company 2010 Annual Report

	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

Schedule F-2	SEC REPORTS	
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 110138-EI	EXPLANATION: Provide a copy of the most recent Form 10-K annual report to the Securities and Exchange Commission and all Form 10-Q quarterly reports filed subsequent to the filing of the latest 10-K.	Type of Data Shown: ___Projected Test Year Ended 12/31/12 ___Prior Year Ended 12/31/11 X Historical Year Ended 12/31/10 Witness: R. S. Teel, C. J. Erickson

Line No.	
1	See Attached

2

Supporting Schedules:

Recap Schedules:

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q
(X) QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2011
OR
( ) TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35203 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
333-98553	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes _X_ *No*____

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes _X_ *No*____ *(Response applicable only to The Southern Company at this time.)*

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Registrant	**Large Accelerated Filer**	**Accelerated Filer**	**Non-accelerated Filer**	**Smaller Reporting Company**
The Southern Company	X			
Alabama Power Company			X	
Georgia Power Company			X	
Gulf Power Company			X	
Mississippi Power Company			X	
Southern Power Company			X	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act.) Yes ___ *No* __X_ (Response applicable to all registrants.)

Registrant	**Description of Common Stock**	**Shares Outstanding at March 31, 2011**
The Southern Company	**Par Value $5 Per Share**	**849,122,723**
Alabama Power Company	**Par Value $40 Per Share**	**30,537,500**
Georgia Power Company	**Without Par Value**	**9,261,500**
Gulf Power Company	**Without Par Value**	**4,142,717**
Mississippi Power Company	**Without Par Value**	**1,121,000**
Southern Power Company	**Par Value $0.01 Per Share**	**1,000**

This combined Form 10-Q is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

INDEX TO QUARTERLY REPORT ON FORM 10-Q
March 31, 2011

INDEX TO QUARTERLY REPORT ON FORM 10-Q
March 31, 2011

Page
Number

PART II - OTHER INFORMATION

DEFINITIONS

Term	Meaning
2007 Retail Rate Plan	Georgia Power's retail rate plan for the years 2008 through 2010
2010 ARP	Alternate Rate Plan approved by the Georgia PSC for Georgia Power which became effective January 1, 2011 and will continue through December 31, 2013
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
Clean Air Act	Clean Air Act Amendments of 1990
DOE	U.S. Department of Energy
Duke Energy	Duke Energy Corporation
ECO Plan	Mississippi Power's Environmental Compliance Overview Plan
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Inc.
Form 10-K	Combined Annual Report on Form 10-K of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power for the year ended December 31, 2010
GAAP	Generally Accepted Accounting Principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IIC	Intercompany Interchange Contract
Internal Revenue Code	Internal Revenue Code of 1986, as amended
IRS	Internal Revenue Service
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mirant	Mirant Corporation
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal unit
Moody's	Moody's Investors Service
MW	Megawatt
MWH	Megawatt-hour
NCCR	Georgia Power's Nuclear Construction Cost Recovery
NDR	Alabama Power's natural disaster reserve
NRC	Nuclear Regulatory Commission
NSR	New Source Review
OCI	Other Comprehensive Income
PEP	Mississippi Power's Performance Evaluation Plan
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
Power Pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power Purchase Agreement
PSC	Public Service Commission
Rate CNP Environmental	Alabama Power's rate certificated new plant environmental
Rate ECR	Alabama Power's energy cost recovery rate mechanism
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power
SCR	Selective catalytic reduction

SCS..	Southern Company Services, Inc.
SEC	Securities and Exchange Commission
Southern Company............................	The Southern Company
Southern Company system................	Southern Company, the traditional operating companies, Southern Power, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear..............................	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company
S&P	Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc.
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
Westinghouse	Westinghouse Electric Company LLC
wholesale revenues............................	revenues generated from sales for resale

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the wholesale business, retail sales, customer growth, economic recovery, fuel cost recovery and other rate actions, environmental regulations and expenditures, future earnings, access to sources of capital, financing activities, start and completion of construction projects, plans and estimated costs for new generation resources, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, storm damage cost recovery and repairs, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water 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 Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and IRS audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- 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 Southern Company's employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to the Plant Vogtle expansion, including Georgia PSC and NRC approvals and potential DOE loan guarantees;
- regulatory approvals and actions related to the Kemper IGCC, including Mississippi PSC approvals and potential DOE loan guarantees;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- 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 Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries 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 Southern 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 Southern Company's and its subsidiaries' credit ratings;
- the ability of Southern Company and its subsidiaries 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 Southern 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 filed by the registrants from time to time with the SEC.

The registrants expressly disclaim any obligation to update any forward-looking statements.

[This page intentionally left blank]

THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2011	For the Three Months Ended March 31, 2010
	(in millions)	
Operating Revenues:		
Retail revenues	**$ 3,396**	$ 3,459
Wholesale revenues	**449**	542
Other electric revenues	**150**	135
Other revenues	**17**	21
Total operating revenues	**4,012**	4,157
Operating Expenses:		
Fuel	**1,476**	1,645
Purchased power	**100**	127
Other operations and maintenance	**944**	908
Depreciation and amortization	**418**	343
Taxes other than income taxes	**220**	212
Total operating expenses	**3,158**	3,235
Operating Income	**854**	922
Other Income and (Expense):		
Allowance for equity funds used during construction	**35**	49
Interest expense, net of amounts capitalized	**(222)**	(222)
Other income (expense), net	**2**	(2)
Total other income and (expense)	**(185)**	(175)
Earnings Before Income Taxes	**669**	747
Income taxes	**231**	236
Consolidated Net Income	**438**	511
Dividends on Preferred and Preference Stock of Subsidiaries	**16**	16
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	**$ 422**	$ 495
Common Stock Data:		
Earnings per share (EPS) -		
Basic EPS	**$0.50**	$0.60
Diluted EPS	**$0.49**	$0.60
Average number of shares of common stock outstanding (in millions)		
Basic	**848**	823
Diluted	**854**	825
Cash dividends paid per share of common stock	**$0.4550**	$0.4375

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2011	2010
	(in millions)	
Operating Activities:		
Consolidated net income	**$ 438**	$ 511
Adjustments to reconcile consolidated net income		
to net cash provided from operating activities --		
Depreciation and amortization, total	**501**	422
Deferred income taxes	**174**	107
Deferred revenues	**(2)**	(20)
Allowance for equity funds used during construction	**(35)**	(49)
Pension, postretirement, and other employee benefits	**(11)**	5
Stock based compensation expense	**21**	19
Generation construction screening costs	**-**	(19)
Other, net	**(14)**	(37)
Changes in certain current assets and liabilities --		
-Receivables	**276**	43
-Fossil fuel stock	**(42)**	133
-Other current assets	**(77)**	(94)
-Accounts payable	**(108)**	(100)
-Accrued taxes	**131**	(73)
-Accrued compensation	**(277)**	(112)
-Other current liabilities	**23**	2
Net cash provided from operating activities	**998**	738
Investing Activities:		
Property additions	**(1,086)**	(1,054)
Investment in restricted cash	**(3)**	-
Distribution of restricted cash	**61**	8
Nuclear decommissioning trust fund purchases	**(928)**	(238)
Nuclear decommissioning trust fund sales	**924**	189
Proceeds from property sales	**14**	-
Cost of removal, net of salvage	**(15)**	(28)
Change in construction payables	**136**	28
Other investing activities	**13**	7
Net cash used for investing activities	**(884)**	(1,088)
Financing Activities:		
Increase (decrease) in notes payable, net	**(54)**	132
Proceeds --		
Long-term debt issuances	**937**	350
Common stock issuances	**193**	147
Redemptions --		
Long-term debt	**(824)**	(256)
Payment of common stock dividends	**(385)**	(359)
Payment of dividends on preferred and preference stock of subsidiaries	**(16)**	(16)
Other financing activities	**(2)**	1
Net cash used for financing activities	**(151)**	(1)
Net Change in Cash and Cash Equivalents	**(37)**	(351)
Cash and Cash Equivalents at Beginning of Period	**447**	690
Cash and Cash Equivalents at End of Period	**$ 410**	$ 339
Supplemental Cash Flow Information:		
Cash paid during the period for --		
Interest (net of $17 and $21 capitalized for 2011 and 2010, respectively)	**$197**	$182
Income taxes (net of refunds)	**(357)**	6
Noncash transactions - accrued property additions at end of period	**531**	373

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2011	At December 31, 2010
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 410**	$ 447
Restricted cash and cash equivalents	**7**	68
Receivables --		
Customer accounts receivable	**1,024**	1,140
Unbilled revenues	**341**	420
Under recovered regulatory clause revenues	**220**	209
Other accounts and notes receivable	**249**	285
Accumulated provision for uncollectible accounts	**(26)**	(25)
Fossil fuel stock, at average cost	**1,350**	1,308
Materials and supplies, at average cost	**828**	827
Vacation pay	**150**	151
Prepaid expenses	**435**	784
Other regulatory assets, current	**199**	210
Other current assets	**53**	59
Total current assets	**5,240**	5,883
Property, Plant, and Equipment:		
In service	**57,408**	56,731
Less accumulated depreciation	**20,384**	20,174
Plant in service, net of depreciation	**37,024**	36,557
Other utility plant, net	**67**	-
Nuclear fuel, at amortized cost	**738**	670
Construction work in progress	**4,872**	4,775
Total property, plant, and equipment	**42,701**	42,002
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**1,369**	1,370
Leveraged leases	**630**	624
Miscellaneous property and investments	**267**	277
Total other property and investments	**2,266**	2,271
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**1,263**	1,280
Prepaid pension costs	**104**	88
Unamortized debt issuance expense	**178**	178
Unamortized loss on reacquired debt	**269**	274
Deferred under recovered regulatory clause revenues	**133**	218
Other regulatory assets, deferred	**2,432**	2,402
Other deferred charges and assets	**433**	436
Total deferred charges and other assets	**4,812**	4,876
Total Assets	**$ 55,019**	$ 55,032

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholders' Equity	At March 31, 2011	At December 31, 2010
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 1,435**	$ 1,301
Notes payable	**1,243**	1,297
Accounts payable	**1,315**	1,275
Customer deposits	**333**	332
Accrued taxes --		
Accrued income taxes	**13**	8
Unrecognized tax benefits	**183**	187
Other accrued taxes	**192**	440
Accrued interest	**259**	225
Accrued vacation pay	**190**	194
Accrued compensation	**165**	438
Liabilities from risk management activities	**133**	152
Other regulatory liabilities, current	**83**	88
Other current liabilities	**493**	535
Total current liabilities	**6,037**	6,472
Long-term Debt	**18,133**	18,154
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**7,673**	7,554
Deferred credits related to income taxes	**233**	235
Accumulated deferred investment tax credits	**525**	509
Employee benefit obligations	**1,575**	1,580
Asset retirement obligations	**1,283**	1,257
Other cost of removal obligations	**1,170**	1,158
Other regulatory liabilities, deferred	**335**	312
Other deferred credits and liabilities	**508**	517
Total deferred credits and other liabilities	**13,302**	13,122
Total Liabilities	**37,472**	37,748
Redeemable Preferred Stock of Subsidiaries	**375**	375
Stockholders' Equity:		
Common Stockholders' Equity:		
Common stock, par value $5 per share --		
Authorized -- 1.5 billion shares		
Issued -- March 31, 2011: 850 million shares		
-- December 31, 2010: 844 million shares		
Treasury -- March 31, 2011: 0.5 million shares		
-- December 31, 2010: 0.5 million shares		
Par value	**4,248**	4,219
Paid-in capital	**3,894**	3,702
Treasury, at cost	**(15)**	(15)
Retained earnings	**8,404**	8,366
Accumulated other comprehensive loss	**(66)**	(70)
Total Common Stockholders' Equity	**16,465**	16,202
Preferred and Preference Stock of Subsidiaries	**707**	707
Total Stockholders' Equity	**17,172**	16,909
Total Liabilities and Stockholders' Equity	**$ 55,019**	$ 55,032

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2011	For the Three Months Ended March 31, 2010
	(in millions)	
Consolidated Net Income	**$ 438**	$ 511
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $2 and $1, respectively	**3**	1
Reclassification adjustment for amounts included in net income, net of tax of $2 and $3, respectively	**3**	6
Marketable securities:		
Change in fair value, net of tax of $- and $1, respectively	**(1)**	2
Pension and other post retirement benefit plans:		
Reclassification adjustment for amounts included in net income, net of tax of $1 and $-, respectively	**(1)**	-
Total other comprehensive income (loss)	**4**	9
Dividends on preferred and preference stock of subsidiaries	**(16)**	(16)
Comprehensive Income	**$ 426**	$ 504

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

FIRST QUARTER 2011 vs. FIRST QUARTER 2010

OVERVIEW

Discussion of the results of operations is focused on Southern Company's primary business of electricity sales in the Southeast by the traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – and Southern Power. The traditional operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market. Southern Company's other business activities include investments in leveraged lease projects and telecommunications. For additional information on these businesses, see BUSINESS – The Southern Company System – "Traditional Operating Companies," "Southern Power," and "Other Businesses" in Item 1 of the Form 10-K.

Southern Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and earnings per share. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Southern Company in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(73)	(14.6)

Southern Company's first quarter 2011 net income after dividends on preferred and preference stock of subsidiaries was $422 million ($0.50 per share) compared to $495 million ($0.60 per share) for the first quarter 2010. The decrease for the first quarter 2011 when compared to the corresponding period in 2010 was primarily the result of decreases in revenues in the first quarter 2011 due to the significantly colder weather in the first quarter 2010, a decrease in wholesale revenues primarily at Alabama Power, a decrease in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power, and increases in operations and maintenance expenses. The decrease for the first quarter 2011 was partially offset by an increase in retail base revenues at Georgia Power pursuant to the 2010 ARP and by increases in revenues associated with new PPAs at Southern Power.

Retail Revenues

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(63)	(1.8)

In the first quarter 2011, retail revenues were $3.4 billion compared to $3.5 billion for the corresponding period in 2010.

Details of the change to retail revenues follow:

	First Quarter 2011	
	(in millions)	*(% change)*
Retail – prior year	$3,459	
Estimated change in –		
Rates and pricing	166	4.8
Sales growth (decline)	(5)	(0.1)
Weather	(90)	(2.6)
Fuel and other cost recovery	(134)	(3.9)
Retail – current year	$3,396	(1.8)%

Revenues associated with changes in rates and pricing increased in the first quarter 2011 when compared to the corresponding period in 2010 primarily due to Georgia Power's retail base rate increase and NCCR revenues. Also contributing to the increase were revenues associated with Alabama Power's Rate CNP Environmental due to the completion of construction projects related to environmental mandates, although there was no increase in the Rate CNP Environmental billing factors in 2011.

Revenues attributable to changes in sales decreased in the first quarter 2011 when compared to the corresponding period in 2010. The decrease was due to a 0.9% decrease in weather-adjusted residential KWH sales and a 0.8% decrease in weather-adjusted commercial KWH sales. In addition, weather-adjusted industrial KWH sales increased 6.4% due to increased production activity in the primary metals and chemical sectors.

Revenues resulting from changes in weather decreased $90 million in the first quarter 2011 as a result of significantly colder weather in the corresponding period in 2010.

Fuel and other cost recovery revenues decreased $134 million in the first quarter 2011 when compared to the corresponding period in 2010. Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power costs, and do not affect net income.

Wholesale Revenues

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(93)	(17.2)

Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives, unit power sales contracts, and short-term opportunity sales. Wholesale revenues from PPAs and unit power sales contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy revenues will vary depending on fuel prices, the market cost of available energy compared to the Southern Company system-owned generation, demand for energy within the Southern Company service territory, and the availability of the Southern Company system generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the variable cost to produce the energy.

In the first quarter 2011, wholesale revenues were $449 million compared to $542 million for the corresponding period in 2010, reflecting a $71 million decrease in energy revenues and a $22 million decrease in capacity revenues. The decrease in the first quarter 2011 was primarily due to a 24.2% decrease in KWH sales mainly due to the expiration of long-term unit power sales contracts in May 2010 at Alabama Power and the capacity subject to those contracts being made available for retail service starting in June 2010. The decrease was partially offset by higher energy and capacity revenues under new PPAs at Southern Power that began in June, July, and December 2010 and January 2011.

Other Electric Revenues

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$15	11.1

In the first quarter 2011, other electric revenues were $150 million compared to $135 million for the corresponding period in 2010. The increase in the first quarter 2011 when compared to the corresponding period in 2010 was primarily the result of an increase in transmission revenues.

Other Revenues

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(4)	(20.3)

In the first quarter 2011, other revenues were $17 million compared to $21 million for the corresponding period in 2010. The decrease in the first quarter 2011 when compared to the corresponding period in 2010 was primarily the result of a $4 million decrease in revenues at SouthernLINC Wireless related to lower average revenue per subscriber and fewer subscribers due to increased competition in the industry.

Fuel and Purchased Power Expenses

First Quarter 2011 vs. First Quarter 2010		
	(change in millions)	*(% change)*
Fuel*	$(169)	(10.3)
Purchased power	(27)	(20.8)
Total fuel and purchased power expenses	$(196)	

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

Fuel and purchased power expenses for the first quarter 2011 were $1.6 billion compared to $1.8 billion for the corresponding period in 2010. The decrease for the first quarter 2011 when compared to the corresponding period in 2010 was primarily the result of a $63 million decrease related to total KWHs generated and purchased and a $133 million net decrease in the average cost of fuel and purchased power. The decrease in total KWHs generated and purchased resulted primarily from a decrease in customer demand, and the net decrease in the cost of fuel and purchased power resulted primarily from a 20.6% decrease in the average cost of gas per KWH generated and a 4.9% decrease in the average cost of coal per KWH generated.

Fuel expenses at the traditional operating companies are generally offset by fuel revenues and do not have a significant effect on net income. See FUTURE EARNINGS POTENTIAL – "State PSC Matters – Retail Fuel Cost Recovery" herein for additional information. Fuel expenses incurred under Southern Power's PPAs are generally the responsibility of the counterparties and do not significantly affect net income.

Details of Southern Company's cost of generation and purchased power are as follows:

Average Cost	First Quarter 2011	First Quarter 2010	Percent Change
	(cents per net KWH)		
Fuel	3.25	3.60	(9.7)
Purchased power	9.25	7.37	25.5

Energy purchases will vary depending on demand for energy within the Southern Company service area, the market cost of available energy as compared to the cost of Southern Company system-generated energy, and the availability of Southern Company system generation.

Other Operations and Maintenance Expenses

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$36	3.8

In the first quarter 2011, other operations and maintenance expenses were $944 million compared to $908 million for the corresponding period in 2010. The increase in the first quarter 2011 when compared to the corresponding period in 2010 was primarily the result of a $30 million increase in scheduled outage and maintenance costs, a $10 million increase in commodity and labor costs, a $9 million increase in transmission and distribution expenses, and a $3 million increase in customer service related costs. The increase was partially offset by a $16 million decrease in administrative and general costs primarily due to decreases in property insurance, pension costs, and other employee benefits.

Depreciation and Amortization

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$75	21.9

In the first quarter 2011, depreciation and amortization was $418 million compared to $343 million for the corresponding period in 2010. The increase for the first quarter 2011 when compared to the corresponding period in 2010 was primarily the result of a $50 million decrease in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power as authorized by the Georgia PSC and additional depreciation on plant in service related to environmental, transmission, and distribution projects. See Note 3 to the financial statements of Southern Company in Item 8 of the Form 10-K under "Retail Regulatory Matters – Georgia Power – Retail Rate Plans" for additional information on the other cost of removal regulatory liability.

Taxes Other Than Income Taxes

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$8	3.9

In the first quarter 2011, taxes other than income taxes were $220 million compared to $212 million for the corresponding period in 2010. The increase for the first quarter 2011 when compared to the corresponding period in 2010 was primarily the result of increases in property and payroll taxes.

Allowance for Equity Funds Used During Construction

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(14)	(28.6)

In the first quarter 2011, AFUDC equity was $35 million compared to $49 million for the corresponding period in 2010. The decrease for the first quarter 2011 when compared to the corresponding period in 2010 was primarily due to the inclusion of Georgia Power's Plant Vogtle Units 3 and 4 construction work in progress in rate base effective January 1, 2011 which reduced the amount of AFUDC capitalized. Also contributing to the decrease was the completion of environmental construction projects at Alabama Power. See Note 3 to the financial statements of Southern Company in Item 8 of the Form 10-K under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and Note (B) to the Condensed Financial Statements under "State PSC Matters – Georgia Power – Nuclear Construction" herein for additional information.

Income Taxes

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(5)	(1.8)

In the first quarter 2011, income taxes were $231 million compared to $236 million for the corresponding period in 2010. The decrease for the first quarter 2011 when compared to the corresponding period in 2010 was primarily the result of lower pre-tax earnings, partially offset by a decrease in the first quarter 2010 in uncertain tax positions at Georgia Power related to state income tax credits that remain subject to litigation. See Notes (B) and (G) to the Condensed Financial Statements under "Income Tax Matters – Georgia State Income Tax Credits" and "Unrecognized Tax Benefits," respectively, herein for additional information.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Southern Company's future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Company's primary business of selling electricity. These factors include the traditional operating companies' 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. Other major factors include profitability of the competitive wholesale supply business and federal regulatory policy. Future earnings for the electricity business 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 and other wholesale customers, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the service area. In addition, the level of future earnings for the wholesale supply business also depends on numerous factors including creditworthiness of customers, total generating capacity available in the Southeast, future acquisitions and construction of generating facilities, and the successful remarketing of capacity as current contracts expire. Changes in economic conditions impact sales for the traditional operating companies and Southern Power, 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. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Southern Company in Item 7 of the Form 10-K.

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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

New Source Review Actions

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – New Source Review Actions" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Environmental Matters – New Source Review Actions" in Item 8 of the Form 10-K for additional information regarding civil actions brought by the EPA against certain Southern Company subsidiaries. The EPA's action against Alabama Power alleged that Alabama Power violated the NSR provisions of the Clean Air Act and related state laws with respect to certain of its coal-fired generating facilities. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power's motion for summary judgment on all remaining claims and dismissed the case with prejudice. The EPA has the right to appeal within 60 days of the order. The ultimate outcome of this matter cannot be determined at this time.

Carbon Dioxide Litigation

Kivalina Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" in Item 8 of the Form 10-K for additional information regarding carbon dioxide litigation. On February 23, 2011, the U.S. Court of Appeals for the Ninth Circuit issued an order staying the case until June 15, 2011. The ultimate outcome of this matter cannot be determined at this time.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Southern Company in Item 7 of the Form 10-K for additional information regarding regulation of air quality. On May 3, 2011, the EPA published a proposed rule, called Utility MACT (Maximum Achievable Control Technology), which would impose stringent emission limits on coal- and oil-fired electric utility steam generating units (EGUs). The proposed rule establishes numeric emission limits for acid gases, mercury, and total particulate matter. Meeting the proposed limits would likely require additional emission control equipment such as scrubbers, SCRs, baghouses, and other control measures at many coal-fired EGUs. Pursuant to a court-approved consent decree, the EPA must issue a final rule by November 16, 2011. Compliance for existing sources would be required three years after the effective date of the final rule. In the proposed rule, the EPA discussed the possibility of a one-year compliance extension which could be granted by the EPA or the states on a case-by-case basis if necessary. If finalized as proposed, compliance with this rule would require significant capital expenditures and compliance costs at many of the facilities of Southern Company's subsidiaries which could impact unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be impacted if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the proposed rule within the proposed compliance period, and the limited compliance period could negatively impact electric system reliability. The outcome of this rulemaking cannot be determined at this time.

In April 2010, the EPA proposed an Industrial Boiler MACT rule that would establish emissions limits for various hazardous air pollutants typically emitted from industrial boilers, including biomass boilers and start-up boilers. The EPA issued the final rules on February 23, 2011 and, at the same time, issued a notice of intent to reconsider the final rules to allow for additional public review and comment. Georgia Power has delayed the decision to convert Plant

Mitchell Unit 3 to biomass until there is greater clarity regarding these regulations. The impact of these regulations will depend on their final form and the outcome of any legal challenges and cannot be determined at this time.

In October 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity which granted some flexibility to affected sources while requiring compliance with Alabama's very strict opacity limits through use of continuous opacity monitoring system data. In a decision published on April 6, 2011, the EPA responded to an environmental group's request for reconsideration by attempting to rescind its previous approval of the Alabama SIP revision. On April 8, 2011, Alabama Power filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit and requested the court to stay the effectiveness of the EPA's attempted rescission pending judicial review. Absent a stay, the EPA's decision will become effective May 6, 2011 and the rule under which Alabama Power has been operating since January 2009 may not be available unless Alabama Power's appeal is resolved in its favor by the court. If the EPA's decision is allowed to take effect, it will likely impact unit availability and result in increased maintenance and compliance costs. The final outcome of this matter cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Southern Company in Item 7 of the Form 10-K for additional information regarding regulation of water quality. On April 20, 2011, the EPA proposed a rule that establishes standards for reducing impacts to fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. The rule focuses on reducing adverse impacts to fish and other aquatic life due to impingement (when fish and other aquatic life are trapped by water flow velocity against a facility's cooling water intake structure screens) and entrainment (when aquatic organisms are drawn through a facility's cooling water system after entering through the cooling water intake structure). Affected cooling water intake structures would have to comply with national impingement standards (for intake velocity or alternatively numeric impingement reduction standards) and entrainment reduction requirements (determined on a case-by-case basis). The rule's proposed impingement standards could require technological improvements to cooling water intake structures at many of Southern Company affiliates' existing generating facilities, including facilities with closed-cycle re-circulating cooling systems (cooling towers). To address the rule's entrainment standards, facilities with once-through cooling systems may have to install cooling towers. New units constructed at existing plants would have to meet the national impingement standards and install closed-cycle cooling or the equivalent to meet the entrainment mandate. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of the facilities of Southern Company's subsidiaries may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking cannot be determined at this time.

State PSC Matters

Retail Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. In previous years, the traditional operating companies have experienced volatility in pricing of fuel commodities with higher than expected pricing for coal and uranium and volatile price swings in natural gas. These higher fuel costs have resulted in total under recovered fuel costs included in the balance sheets of Alabama Power, Georgia Power, and Gulf Power of approximately $348 million at March 31, 2011. Mississippi Power collected all previously under recovered fuel costs and, as of March 31, 2011, had a total over recovered fuel balance of $58 million. At December 31, 2010, total under recovered fuel costs included in the balance sheets of Alabama Power, Georgia Power, and Gulf Power were approximately $420 million and Mississippi Power had a total over recovered fuel balance of $55 million. Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changing the billing factor has no significant effect on Southern Company's revenues or net income, but does impact annual cash flow. The traditional operating companies continuously monitor the under or over recovered fuel cost balances.

On March 1, 2011, Georgia Power filed a request with the Georgia PSC to decrease fuel rates by 0.61%. The decrease would reduce Georgia Power's annual billings by approximately $43 million. The decrease in fuel costs is driven primarily by lower natural gas prices than those included in current rates. That decrease is a result of increases in natural gas supplies from the production of shale gas and lower industrial demand. If approved, the new rates will go into effect June 1, 2011. The ultimate outcome of this matter cannot be determined at this time.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Fuel Cost Recovery" and "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information.

Alabama Power Retail Regulatory Matters

Natural Disaster Reserve

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Natural Disaster Reserve" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Natural Disaster Reserve" in Item 8 of the Form 10-K.

On April 27, 2011, devastating storms swept through the central part of Alabama causing significant damage in parts of the service territory of Alabama Power. Over 400,000 of Alabama Power's 1.4 million customers were without electrical service immediately after the storms, resulting from significant damage to Alabama Power's transmission and distribution facilities. The preliminary estimated cost associated with repairing the damage to facilities and restoring electrical service to customers is between $40 million and $55 million for operations and maintenance expenses and between $180 million and $225 million for capital expenditures. Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to Alabama Power's transmission and distribution facilities.

At March 31, 2011, the NDR had an accumulated balance of $127 million, which is included in the Condensed Balance Sheets herein under other regulatory liabilities, deferred. The accruals are reflected as operations and maintenance expenses in the Condensed Statements of Income herein.

Georgia Power Retail Regulatory Matters

Plant Branch Units 1 and 2 De-certification

See "Environmental Matters – Air Quality" and "– Water Quality" herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Byproducts" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Rate Plans" in Item 8 of the Form 10-K for additional information regarding potential rules and regulations being developed by the EPA, including the Utility MACT rule for coal- and oil-fired EGUs, revisions to effluent guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; Georgia Power's analysis of the potential costs and benefits of installing the required controls on its coal-fired generating units in light of these regulations; and the 2010 ARP.

On March 22, 2011, the board of the Georgia Department of Natural Resources began consideration of modifications to the Georgia Multi-Pollutant Rule. The proposed modifications would change the compliance dates for certain of Georgia Power's coal-fired generating units as follows:

Scherer 3	July 1, 2011
Branch 1	December 31, 2013
Branch 2	October 1, 2013
Branch 3	October 1, 2015
Branch 4	December 31, 2015

The Multi-Pollutant Rule is designed to reduce emissions of mercury, sulfur dioxide, and nitrogen oxides statewide. The Utility MACT rule will also regulate emissions of mercury, in addition to other air pollutants. All required controls, including SCR, scrubber, and baghouse, are expected to be operational at Plant Scherer Unit 3 by the required compliance date. As a result of these proposed rules, Georgia Power's management expects to request that the Georgia PSC approve de-certification of its Plant Branch Units 1 and 2, totaling 569 MWs of capacity, as of the effective dates for controls under the Multi-Pollutant Rule as revised. Georgia Power continues to analyze the potential costs and benefits of installing the required controls on its remaining coal-fired units, including Plant Branch Units 3 and 4, in light of the proposed air quality rules, as well as additional potential federal regulations related to water quality and coal combustion byproducts. Georgia Power may determine that retiring and replacing certain of its existing units with new generating resources or purchased power is more economically efficient than installing the required controls.

Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated integrated resource plan will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. Georgia Power currently expects to file an update to its integrated resource plan in late summer 2011, which would include the Plant Branch Units 1 and 2 de-certification request. In connection with this filing, Georgia Power expects to request the Georgia PSC to approve the deferral and related amortization of the retail portion of the related costs associated with the de-certification request. Georgia Power moved the retail portion of the net carrying value of Plant Branch Units 1 and 2 from plant in service, net of depreciation, to other utility plant, net of depreciation. Consistent with current ratemaking treatment, Georgia Power will continue to depreciate these units using the composite straight-line rates approved by the Georgia PSC, and upon actual retirement, expects to include the units' remaining net carrying value in rate base. However, the recovery periods for these units may change in connection with Georgia Power's updated integrated resource plan. As a result of this regulatory treatment, the de-certification of Plant Branch Units 1 and 2 is not expected to have a significant impact on Southern Company's financial statements.

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

Storm Damage Reserve

During April 2011, severe storms in Georgia caused significant damage to Georgia Power's distribution and transmission facilities. Georgia Power maintains a reserve for property damage to cover the operating and maintenance cost of damages from major storms to its transmission and distribution lines as mandated by the Georgia PSC. As a result of this regulatory treatment, the storms are not expected to have a material impact on Southern Company's financial statements. See Note 1 to the financial statements of Southern Company under "Storm Damage Reserves" in Item 8 of the Form 10-K for additional information.

Income Tax Matters

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects to be placed in service in 2011). Additionally, in December 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 will have a positive impact on the future cash flows of Southern Company. On March 29, 2011, the IRS issued additional guidance and safe harbors relating to the 50% and 100% bonus depreciation rules. Based on this guidance, Southern Company estimates the potential increased cash flow for 2011 to be between approximately $350 million and $450 million. The ultimate outcome of this matter cannot be determined at this time.

Construction Program

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. Southern Company intends to continue its strategy of developing and constructing new generating facilities, including natural gas, biomass, and potentially solar units at Southern Power, natural gas and new nuclear units at Georgia Power, and the Kemper IGCC facility at Mississippi Power, as well as adding environmental control equipment and expanding the transmission and distribution systems. For the traditional operating companies, major generation construction projects are subject to state PSC approvals in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. See Note 7 to the financial statements of Southern Company under "Construction Program" in Item 8 of the Form 10-K for estimated construction expenditures for the next three years. In addition, see Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Nuclear Construction," "Retail Regulatory Matters – Georgia Power – Other Construction," and "Retail Regulatory Matters – Mississippi Power Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "State PSC Matters – Georgia Power – Nuclear Construction" and "State PSC Matters – Mississippi Power – Integrated Coal Gasification Combined Cycle" herein for additional information.

On March 11, 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. According to published reports, the owner of these units is continuing work to stabilize these units following a loss of operation of the cooling systems for the units. While the Southern Company system will continue to monitor this developing situation, it has not identified any immediate impact to the licensing and construction of Plant Vogtle Units 3 and 4 or the operation of the existing nuclear generating units of Alabama Power and Georgia Power.

The events in Japan have created uncertainties that may affect transportation, price of fuels, availability of equipment from Japanese manufacturers, and future costs for operating nuclear plants. Specifically, the NRC plans to perform additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements.

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

Other Matters

Southern Company and its subsidiaries are involved in various other matters being litigated, regulatory matters, and certain tax-related issues that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries 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 Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Southern Company in Item 8 of the Form 10-K, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on Southern Company's financial statements.

See the Notes to the Condensed Financial Statements herein for discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Southern Company in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Southern 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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Southern Company in Item 7 of the Form 10-K for a complete discussion of Southern Company's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, Unbilled Revenues, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Company's financial condition remained stable at March 31, 2011. Southern 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.

Net cash provided from operating activities totaled $998 million for the first quarter 2011, an increase of $260 million from the corresponding period in 2010. Significant changes in operating cash flow for the first quarter 2011 as compared to the corresponding period in 2010 include a decrease in accounts receivable balances primarily due to greater recovery of fuel costs. Net cash used for investing activities totaled $884 million for the first quarter 2011, a decrease of $204 million from the corresponding period in 2010. This decrease was primarily due to an increase in construction-related accounts payable. Net cash used for financing activities totaled $151 million for the first quarter 2011, an increase of $150 million from the corresponding period in 2010. This increase was primarily due to a decrease in notes payable.

Significant balance sheet changes for the first quarter 2011 include a decrease in prepaid expenses of $349 million due to a reduction in prepaid income taxes and an increase of $699 million in total property, plant, and equipment for the installation of equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities. Other significant changes include an increase in equity of $263 million.

The market price of Southern Company's common stock at March 31, 2011 was $38.11 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $19.39 per share, representing a market-to-book ratio of 196.5%, compared to $38.23, $19.21, and 199.0%, respectively, at the end of 2010. The dividend for the first quarter 2011 was $0.4550 per share compared to $0.4375 per share in the first quarter 2010. In April 2011, the quarterly dividend payable in June 2011 was increased to $0.4725 per share.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company in Item 7 of the Form 10-K for a description of Southern Company's capital requirements for the construction programs of its subsidiaries and other funding requirements associated with scheduled maturities of long-term debt, as well as the related interest, preferred and preference stock dividends, leases, trust funding requirements, other purchase commitments, unrecognized tax benefits and interest, and derivative obligations. Approximately $1.4 billion will be required through March 31, 2012 for maturities and announced repurchases of long-term debt.

The construction programs of Southern Company's subsidiaries are currently estimated to include a base level investment of $4.9 billion, $5.1 billion, and $4.5 billion for 2011, 2012, and 2013, respectively. Included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $341 million, $427 million, and $452 million for 2011, 2012, and 2013, respectively. In addition, Southern Company currently estimates that potential incremental investments to comply with anticipated new environmental regulations could range from $74 million to $289 million for 2011, $191 million to $670 million for 2012, and $476 million to $1.9 billion for 2013. If the EPA's proposed Utility MACT rule is finalized as proposed, Southern Company estimates the potential investments in 2011 through 2013 for new environmental regulations will be closer to the upper end of the ranges set forth above. The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Sources of Capital

Southern Company intends to meet its future capital needs through internal cash flow and external security issuances. Equity capital can be provided from any combination of Southern Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital to be raised in 2011, as well as in subsequent years, will be contingent on Southern Company's investment opportunities.

Except as described below with respect to potential DOE loan guarantees, the traditional operating companies and Southern Power plan to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Southern Company in Item 7 of the Form 10-K for additional information.

In June 2010, Georgia Power reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future Georgia Power borrowings related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to Georgia Power and secured by a first priority lien on Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs or approximately $3.4 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to receipt of the combined Construction and Operating License for Plant Vogtle Units 3 and 4 from the NRC, negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. There can be no assurance that the DOE will issue loan guarantees for Georgia Power.

In addition, Mississippi Power has applied to the DOE for federal loan guarantees to finance a portion of the eligible construction costs of the Kemper IGCC. Mississippi Power is in advanced due diligence with the DOE. There can be no assurance that the DOE will issue federal loan guarantees for Mississippi Power.

Southern Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet cash needs as well as scheduled maturities of long-term debt. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets, including commercial paper programs which are backed by bank credit facilities.

At March 31, 2011, Southern Company and its subsidiaries had approximately $410 million of cash and cash equivalents and approximately $4.8 billion of unused committed credit arrangements with banks, of which $1.6 billion expire in 2011 and $3.3 billion expire in 2012. Of the credit arrangements expiring in 2011 and 2012, $81 million contain provisions allowing two-year term loans executable at expiration and $952 million contain provisions allowing one-year term loans executable at expiration. At March 31, 2011, approximately $1.4 billion of the credit facilities were dedicated to providing liquidity support to the traditional operating companies' variable rate pollution control revenue bonds. See Note 6 to the financial statements of Southern Company under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information. The traditional operating companies 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 each of the traditional operating companies. At March 31, 2011, the Southern Company system had approximately $1.2 billion of commercial paper borrowings outstanding with a weighted average interest rate of 0.3% per annum. During the first quarter 2011, Southern Company had an average of $1.2 billion of commercial paper outstanding at a weighted average interest rate of 0.3% per annum and the maximum amount outstanding was $1.6 billion. Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Off-Balance Sheet Financing Arrangements

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Off-Balance Sheet Financing Arrangements" of Southern Company in Item 7 and Note 7 to the financial statements of Southern Company under "Operating Leases" in Item 8 of the Form 10-K for information related to Mississippi Power's lease of a combined cycle generating facility at Plant Daniel. In April 2010, Mississippi Power was required to notify the lessor, Juniper Capital L.P., if it intended to terminate the lease at the end of the initial term expiring in October 2011. Mississippi Power chose not to give notice to terminate the lease. Mississippi Power has the option to purchase the units or renew the lease. Mississippi Power is required to provide notice of its intent to either renew the lease or purchase the facility by July 2011. The ultimate outcome of this matter cannot be determined at this time.

Credit Rating Risk

Southern 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 of certain subsidiaries to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, energy price risk management, and construction of new generation. At March 31, 2011, the maximum potential collateral requirements under these contracts at a BBB and Baa2 rating were approximately $9 million and at a BBB- and/or Baa3 rating were approximately $495 million. At March 31, 2011, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $2.5 billion. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Southern Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Southern Company is exposed to market risks, primarily commodity price risk and interest rate risk. Southern Company may also occasionally have limited exposure to foreign currency exchange rates. To manage the volatility attributable to these exposures, Southern Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to Southern Company's policies in areas such as counterparty exposure and risk management practices. Southern 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.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies enter 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 traditional operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs. Southern Company had no material change in market risk exposure for the first quarter 2011 when compared with the December 31, 2010 reporting period.

The changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, for the three months ended March 31, 2011 were as follows:

	First Quarter 2011 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (196)
Contracts realized or settled	38
Current period changes[(a)]	-
Contracts outstanding at the end of the period, assets (liabilities), net	$ (158)

(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 three months ended March 31, 2011 was an increase of $38 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of mmBtu and prices of natural gas. At March 31, 2011, Southern Company had a net hedge volume of 154.2 million mmBtu with a weighted average contract cost approximately $1.09 per mmBtu above market prices, compared to 149.3 million mmBtu at December 31, 2010 with a weighted average contract cost approximately $1.35 per mmBtu above market prices. The majority of the natural gas hedges are recovered through the traditional operating companies' fuel cost recovery clauses.

The fair value of energy-related derivative contracts by hedge designation reflected in the financial statements as assets (liabilities) consists of the following:

Asset (Liability) Derivatives	**March 31, 2011**	**December 31, 2010**
	(in millions)	
Regulatory hedges	$ (156)	$ (193)
Cash flow hedges	-	(1)
Not designated	(2)	(2)
Total fair value	$ (158)	$ (196)

Energy-related derivative contracts which are designated as regulatory hedges relate to the traditional operating companies' fuel-hedging programs, where 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 clauses. Gains and losses on energy-related derivatives that are designated as cash flow hedges are used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Total net unrealized pre-tax gains (losses) recognized in income for the three months ended March 31, 2011 and 2010 were not material.

Southern Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2011 were as follows:

	March 31, 2011 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ -	$ -	$ -	$-
Level 2	(158)	(125)	(33)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(158)	$(125)	$(33)	$-

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 Southern 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.

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Southern Company in Item 7 and Note 1 under "Financial Instruments" and Note 11 to the financial statements of Southern Company in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

During the first quarter 2011, Southern Company issued approximately 5.8 million shares of common stock for $193 million through the Southern Investment Plan and employee and director stock plans. The proceeds were primarily used for general corporate purposes, including the investment by Southern Company in its subsidiaries, and to repay short-term indebtedness.

In January 2011, Georgia Power's $100 million aggregate principal amount of Series S 4.0% Senior Notes due January 15, 2011 matured.

In January 2011, Georgia Power issued $300 million aggregate principal amount of Series 2011A Floating Rate Senior Notes due January 15, 2013. The proceeds were used for general corporate purposes, including Georgia Power's continuous construction program.

In March 2011, Alabama Power issued $250 million aggregate principal amount of Series 2011A 5.50% Senior Notes due March 15, 2041. The proceeds were used for general corporate purposes, including Alabama Power's continuous construction program.

In March 2011, Georgia Power's $300 million variable rate bank term loan due on March 4, 2011 matured and was partially replaced by two one-year $125 million aggregate principal amount variable rate bank loans that bear interest based on one-month LIBOR.

Subsequent to March 31, 2011, Georgia Power issued $250 million aggregate principal amount of Series 2011B 3.0% Senior Notes due April 15, 2016. The proceeds were used to repay short-term debt and for general corporate purposes, including Georgia Power's continuous construction program.

Also subsequent to March 31, 2011, Georgia Power purchased and is holding $113.5 million of pollution control revenue bonds. The bonds are expected to be re-marketed to investors at a future date.

Subsequent to March 31, 2011, Gulf Power extended the maturity date of a $110 million bank note until June 30, 2011.

Subsequent to March 31, 2011, Mississippi Power entered into a one-year $75 million aggregate principal amount long-term floating rate bank loan that bears interest based on one-month LIBOR. The proceeds were used to repay short-term debt and for general corporate purposes, including Mississippi Power's continuous construction program.

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

PART I

Item 3. Quantitative And Qualitative Disclosures About Market Risk.

See MANAGEMENT'S DISCUSSION AND ANALYSIS - FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein for each registrant and Note 1 to the financial statements of each registrant under "Financial Instruments," Note 11 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Note 10 to the financial statements of Gulf Power and Mississippi Power, and Note 9 to the financial statements of Southern Power in Item 8 of the Form 10-K. Also, see Note (H) to the Condensed Financial Statements herein for information relating to derivative instruments.

Item 4. Controls and Procedures.

(a) Evaluation of disclosure controls and procedures.

As of the end of the period covered by this quarterly report, Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Sections 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

(b) Changes in internal controls.

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the first quarter 2011 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting.

[This page intentionally left blank]

ALABAMA POWER COMPANY

ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2011	2010
	(in millions)	
Operating Revenues:		
Retail revenues	**$ 1,126**	$ 1,176
Wholesale revenues, non-affiliates	**68**	172
Wholesale revenues, affiliates	**75**	98
Other revenues	**51**	49
Total operating revenues	**1,320**	1,495
Operating Expenses:		
Fuel	**395**	489
Purchased power, non-affiliates	**11**	18
Purchased power, affiliates	**46**	52
Other operations and maintenance	**297**	310
Depreciation and amortization	**157**	145
Taxes other than income taxes	**85**	82
Total operating expenses	**991**	1,096
Operating Income	**329**	399
Other Income and (Expense):		
Allowance for equity funds used during construction	**5**	13
Interest income	**4**	4
Interest expense, net of amounts capitalized	**(74)**	(75)
Other income (expense), net	**(6)**	(6)
Total other income and (expense)	**(71)**	(64)
Earnings Before Income Taxes	**258**	335
Income taxes	**96**	122
Net Income	**162**	213
Dividends on Preferred and Preference Stock	**10**	10
Net Income After Dividends on Preferred and Preference Stock	**$ 152**	$ 203

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2011	2010
	(in millions)	
Net Income After Dividends on Preferred and Preference Stock	**$ 152**	$ 203
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $2 and $-, respectively	**2**	-
Reclassification adjustment for amounts included in net income, net of tax of $- and $1, respectively	**-**	1
Total other comprehensive income (loss)	**2**	1
Comprehensive Income	**$ 154**	$ 204

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2011	2010
	(in millions)	
Operating Activities:		
Net income	**$ 162**	$ 213
Adjustments to reconcile net income		
to net cash provided from operating activities --		
Depreciation and amortization, total	**185**	168
Deferred income taxes	**59**	47
Allowance for equity funds used during construction	**(5)**	(13)
Pension, postretirement, and other employee benefits	**(11)**	(8)
Stock based compensation expense	**3**	3
Hedge settlements	**4**	-
Storm damage accruals	**1**	2
Other, net	**(4)**	4
Changes in certain current assets and liabilities --		
-Receivables	**51**	11
-Fossil fuel stock	**3**	13
-Materials and supplies	**10**	(3)
-Other current assets	**(69)**	(78)
-Accounts payable	**(153)**	(75)
-Accrued taxes	**160**	69
-Accrued compensation	**(67)**	(41)
-Other current liabilities	**(2)**	(38)
Net cash provided from operating activities	**327**	274
Investing Activities:		
Property additions	**(213)**	(255)
Distribution of restricted cash from pollution control revenue bonds	**11**	5
Nuclear decommissioning trust fund purchases	**(97)**	(39)
Nuclear decommissioning trust fund sales	**97**	39
Cost of removal, net of salvage	**(8)**	(5)
Change in construction payables	**(2)**	(26)
Other investing activities	**(12)**	(17)
Net cash used for investing activities	**(224)**	(298)
Financing Activities:		
Proceeds --		
Capital contributions from parent company	**5**	6
Senior notes issuances	**250**	-
Redemptions --		
Senior notes	**(200)**	-
Payment of preferred and preference stock dividends	**(10)**	(10)
Payment of common stock dividends	**(138)**	(136)
Other financing activities	**(5)**	(1)
Net cash used for financing activities	**(98)**	(141)
Net Change in Cash and Cash Equivalents	**5**	(165)
Cash and Cash Equivalents at Beginning of Period	**154**	368
Cash and Cash Equivalents at End of Period	**$ 159**	$ 203
Supplemental Cash Flow Information:		
Cash paid during the period for --		
Interest (net of $2 and $5 capitalized for 2011 and 2010, respectively)	**$72**	$59
Income taxes (net of refunds)	**(110)**	19
Noncash transactions - accrued property additions at end of period	**26**	48

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2011	At December 31, 2010
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 159**	$ 154
Restricted cash and cash equivalents	**7**	18
Receivables --		
Customer accounts receivable	**321**	362
Unbilled revenues	**110**	153
Under recovered regulatory clause revenues	**10**	5
Other accounts and notes receivable	**33**	35
Affiliated companies	**89**	57
Accumulated provision for uncollectible accounts	**(10)**	(10)
Fossil fuel stock, at average cost	**388**	391
Materials and supplies, at average cost	**336**	346
Vacation pay	**56**	55
Prepaid expenses	**140**	208
Other regulatory assets, current	**32**	38
Other current assets	**7**	10
Total current assets	**1,678**	1,822
Property, Plant, and Equipment:		
In service	**20,218**	19,966
Less accumulated provision for depreciation	**7,038**	6,931
Plant in service, net of depreciation	**13,180**	13,035
Nuclear fuel, at amortized cost	**317**	283
Construction work in progress	**428**	547
Total property, plant, and equipment	**13,925**	13,865
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**63**	64
Nuclear decommissioning trusts, at fair value	**578**	552
Miscellaneous property and investments	**71**	71
Total other property and investments	**712**	687
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**456**	488
Prepaid pension costs	**267**	257
Deferred under recovered regulatory clause revenues	**5**	4
Other regulatory assets, deferred	**673**	675
Other deferred charges and assets	**209**	196
Total deferred charges and other assets	**1,610**	1,620
Total Assets	**$ 17,925**	$ 17,994

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	At March 31, 2011	At December 31, 2010
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ -**	$ 200
Accounts payable --		
Affiliated	**158**	210
Other	**170**	273
Customer deposits	**86**	86
Accrued taxes --		
Accrued income taxes	**4**	2
Other accrued taxes	**51**	32
Accrued interest	**62**	63
Accrued vacation pay	**45**	45
Accrued compensation	**34**	99
Liabilities from risk management activities	**24**	31
Over recovered regulatory clause revenues	**23**	22
Other current liabilities	**39**	41
Total current liabilities	**696**	1,104
Long-term Debt	**6,235**	5,987
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,774**	2,747
Deferred credits related to income taxes	**86**	85
Accumulated deferred investment tax credits	**155**	157
Employee benefit obligations	**309**	311
Asset retirement obligations	**528**	520
Other cost of removal obligations	**712**	701
Other regulatory liabilities, deferred	**236**	217
Other deferred credits and liabilities	**90**	87
Total deferred credits and other liabilities	**4,890**	4,825
Total Liabilities	**11,821**	11,916
Redeemable Preferred Stock	**342**	342
Preference Stock	**343**	343
Common Stockholder's Equity:		
Common stock, par value $40 per share --		
Authorized - 40,000,000 shares		
Outstanding - 30,537,500 shares	**1,222**	1,222
Paid-in capital	**2,166**	2,156
Retained earnings	**2,036**	2,022
Accumulated other comprehensive loss	**(5)**	(7)
Total common stockholder's equity	**5,419**	5,393
Total Liabilities and Stockholder's Equity	**$ 17,925**	$ 17,994

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

FIRST QUARTER 2011 vs. FIRST QUARTER 2010

OVERVIEW

Alabama Power operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located within the State of Alabama and to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of Alabama Power's primary business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel, capital expenditures, and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Alabama Power for the foreseeable future.

Alabama Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Alabama Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(51)	(25.1)

Alabama Power's net income after dividends on preferred and preference stock for the first quarter 2011 was $152 million compared to $203 million for the corresponding period in 2010. The decrease was primarily due to reductions in wholesale revenues from sales to non-affiliates in the first quarter 2011 and significantly colder weather in the first quarter 2010. The decrease in revenue was partially offset by decreases in operations and maintenance expenses and an increase in revenues under Rate CNP Environmental associated with the completion of construction projects related to environmental mandates.

Retail Revenues

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(50)	(4.3)

In the first quarter 2011, retail revenues were $1.13 billion compared to $1.18 billion for the corresponding period in 2010.

Details of the change to retail revenues are as follows:

	First Quarter 2011	
	(in millions)	*(% change)*
Retail – prior year	$1,176	
Estimated change in –		
Rates and pricing	26	2.2
Sales growth (decline)	(3)	(0.2)
Weather	(45)	(3.9)
Fuel and other cost recovery	(28)	(2.4)
Retail – current year	$1,126	(4.3)%

Revenues associated with changes in rates and pricing increased in the first quarter 2011 when compared to the corresponding period in 2010 primarily due to increased revenues associated with Rate CNP Environmental. The increase was due to the completion of construction projects related to environmental mandates, although there was no increase in the Rate CNP Environmental billing factors in 2011.

Revenues attributable to changes in sales decreased slightly in the first quarter 2011 from the corresponding period in 2010. Weather-adjusted residential KWH energy sales decreased 2.7% due to a decrease in customer demand. Weather-adjusted commercial KWH energy sales decreased 1.0% due to decreases in the number of customers and demand. Industrial KWH energy sales increased 9.5% due to an increase in demand resulting from changes in production levels primarily in the chemical and primary metals sectors.

Revenues resulting from changes in weather decreased in the first quarter 2011 when compared to the corresponding period in 2010. Residential and commercial sales revenues decreased 7.1% and 1.5%, respectively, as a result of significantly colder weather in the corresponding period in 2010.

Fuel and other cost recovery revenues decreased in the first quarter 2011 when compared to the corresponding period in 2010 primarily due to a decrease in fuel costs associated with decreased KWH generation and a decrease in costs associated with PPAs certificated by the Alabama PSC. Electric rates include provisions to recognize the full recovery of fuel costs, purchased power costs, PPAs certificated by the Alabama PSC, and costs associated with the NDR. Under these provisions, fuel and other cost recovery revenues generally equal fuel and other cost recovery expenses and do not impact net income.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Rate Adjustments" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information.

Wholesale Revenues – Non-Affiliates

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(104)	(60.5)

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

In the first quarter 2011, wholesale revenues from non-affiliates were $68 million compared to $172 million for the corresponding period in 2010, reflecting a $55 million decrease in revenue from energy sales and a $49 million decrease in capacity revenue. This decrease was primarily due to a 66.3% decrease in KWH sales, partially offset by a

16.8% increase in the price. In May 2010, the long-term unit power sales contracts expired and the unit power sales capacity revenues ceased, resulting in a $102 million revenue reduction as compared to the first quarter 2010. Beginning in June 2010, such capacity subject to the unit power sales contracts became available for retail service. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS – "Operating Revenues" of Alabama Power in Item 7 of the Form 10-K for additional information.

Wholesale Revenues – Affiliates

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(23)	(23.5)

Wholesale revenues from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost.

In the first quarter 2011, wholesale revenues from affiliates were $75 million compared to $98 million for the corresponding period in 2010. This decrease was due to a 19.0% decrease in price and a 5.3% decrease in KWH sales.

Fuel and Purchased Power Expenses

First Quarter 2011 vs. First Quarter 2010		
	(change in millions)	*(% change)*
Fuel*	$(94)	(19.2)
Purchased power – non-affiliates	(7)	(38.9)
Purchased power – affiliates	(6)	(11.5)
Total fuel and purchased power expenses	$(107)	

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

In the first quarter 2011, total fuel and purchased power expenses were $452 million compared to $559 million for the corresponding period in 2010. This decrease was primarily due to a $49 million decrease in total KWHs generated, a $28 million decrease in the cost of fuel, and a $20 million decrease in the average cost of purchased power.

Fuel and purchased power transactions do not have a significant impact on earnings since energy expenses are generally offset by energy revenues through Rate ECR. See FUTURE EARNINGS POTENTIAL – "Alabama PSC Matters – Retail Fuel Cost Recovery" herein for additional information.

Details of Alabama Power's cost of generation and purchased power are as follows:

Average Cost	First Quarter 2011	First Quarter 2010	Percent Change
	(cents per net KWH)		
Fuel*	2.62	2.80	(6.4)
Purchased power	5.26	7.08	(25.7)

* KWHs generated by hydro are excluded from the average cost of fuel.

In the first quarter 2011, fuel expense was $395 million compared to $489 million for the corresponding period in 2010. The $94 million decrease was due to a 14.6% decrease in KWHs generated by coal, an 8.0% decrease in KWHs generated by natural gas, and a 17.8% decrease in the average cost of KWHs generated by natural gas, which excludes fuel associated with tolling agreements.

Non-Affiliates

In the first quarter 2011, purchased power expense from non-affiliates was $11 million compared to $18 million for the corresponding period in 2010. This decrease was related to a 75.6% decrease in the amount of energy purchased, partially offset by a 140.3% increase in the average cost per KWH.

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

Affiliates

In the first quarter 2011, purchased power expense from affiliates was $46 million compared to $52 million for the corresponding period in 2010. This decrease was related to a 39.9% decrease in the average cost per KWH, partially offset by a 14.0% increase in the amount of energy purchased.

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

Other Operations and Maintenance Expenses

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(13)	(4.2)

In the first quarter 2011, other operations and maintenance expenses were $297 million compared to $310 million for the corresponding period in 2010. Administration and general expenses decreased $9 million related to decreases in affiliated service companies' expenses, property insurance expense, employee medical and other benefit-related expenses, and injuries and damages expenses. Nuclear production expenses decreased $8 million primarily due to a change to the nuclear maintenance outage accounting process associated with the routine refueling activities, as approved by the Alabama PSC in August 2010. As a result, no nuclear maintenance outage expenses will be recognized in 2011, reducing nuclear production expense by approximately $50 million as compared to 2010. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Outage Accounting Order" of Alabama Power in Item 7 of the Form 10-K for additional information. In addition, the decrease in nuclear production expenses was partially offset by an increase in maintenance costs related to increases in labor. Transmission and distribution expenses increased $4 million primarily due to overhead line clearing costs.

Depreciation and Amortization

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$12	8.3

In the first quarter 2011, depreciation and amortization was $157 million compared to $145 million for the corresponding period in 2010. The increase was due to additions of property, plant, and equipment primarily related to environmental mandates (which are offset by revenues associated with Rate CNP Environmental), distribution, and transmission projects.

Allowance for Equity Funds Used During Construction

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(8)	(61.5)

In the first quarter 2011, AFUDC equity was $5 million compared to $13 million for the corresponding period in 2010. This decrease was due to the completion of environmental construction projects at Plants Barry, Gaston, and Miller.

Income Taxes

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(26)	(21.3)

For the first quarter 2011, income taxes were $96 million compared to $122 million for the corresponding period in 2010. This decrease was primarily due to lower pre-tax earnings.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Alabama Power's future earnings potential. The level of Alabama Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Alabama Power's primary business of selling electricity. These factors include Alabama Power'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 Alabama Power's service area. Changes in economic conditions impact sales for Alabama Power 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. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Alabama Power in Item 7 of the Form 10-K.

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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

New Source Review Actions

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – New Source Review Actions" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Environmental Matters – New Source Review Actions" in Item 8 of the Form 10-K for additional information regarding civil actions brought by the EPA against certain Southern Company subsidiaries. The EPA's action against Alabama Power alleged that Alabama Power violated the NSR provisions of the Clean Air Act and related state laws with respect to certain of its coal-fired generating facilities. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power's motion for summary judgment on all remaining claims and dismissed the case with prejudice. The EPA has the right to appeal within 60 days of the order. The ultimate outcome of this matter cannot be determined at this time.

Carbon Dioxide Litigation

Kivalina Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" in Item 8 of the Form 10-K for additional information regarding carbon dioxide litigation. On February 23, 2011, the U.S. Court of Appeals for the Ninth Circuit issued an order staying the case until June 15, 2011. The ultimate outcome of this matter cannot be determined at this time.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Alabama Power in Item 7 of the Form 10-K for additional information regarding regulation of air quality. On May 3, 2011, the EPA published a proposed rule, called Utility MACT (Maximum Achievable Control Technology), which would impose stringent emission limits on coal- and oil-fired electric utility steam generating units (EGUs). The proposed rule establishes numeric emission limits for acid gases, mercury, and total particulate matter. Meeting the proposed limits would likely require additional emission control equipment such as scrubbers, SCRs, baghouses, and other control measures at many coal-fired EGUs. Pursuant to a court-approved consent decree, the EPA must issue a final rule by November 16, 2011. Compliance for existing sources would be required three years after the effective date of the final rule. In the proposed rule, the EPA discussed the possibility of a one-year compliance extension which could be granted by the EPA or the states on a case-by-case basis if necessary. If finalized as proposed, compliance with this rule would require significant capital expenditures and compliance costs at many of Alabama Power's facilities which could impact unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be impacted if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the proposed rule within the proposed compliance period, and the limited compliance period could negatively impact electric system reliability. The outcome of this rulemaking cannot be determined at this time.

In October 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity which granted some flexibility to affected sources while requiring compliance with Alabama's very strict opacity limits through use of continuous opacity monitoring system data. In a decision published on April 6, 2011, the EPA responded to an environmental group's request for reconsideration by attempting to rescind its previous approval of the Alabama SIP revision. On April 8, 2011, Alabama Power filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit and requested the court to stay the effectiveness of the EPA's attempted rescission pending judicial review. Absent a stay, the EPA's decision will become effective May 6, 2011 and the rule under which Alabama Power has been operating since January 2009 may not be available unless Alabama Power's appeal is resolved in its favor by the court. If the EPA's decision is allowed to take effect, it will likely impact unit availability and result in increased maintenance and compliance costs. The final outcome of this matter cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Alabama Power in Item 7 of the Form 10-K for additional information regarding regulation of water quality. On April 20, 2011, the EPA proposed a rule that establishes standards for reducing impacts to fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. The rule focuses on reducing adverse impacts to fish and other aquatic life due to impingement (when fish and other aquatic life are trapped by water flow velocity against a facility's cooling water intake structure screens) and entrainment (when aquatic organisms are drawn through a facility's cooling water system after entering through the cooling water intake structure). Affected cooling water intake structures would have to comply with national impingement standards (for intake velocity or alternatively numeric impingement reduction standards) and entrainment reduction requirements (determined on a case-by-case basis). The rule's proposed impingement standards could require technological improvements to cooling water intake structures at many of Alabama Power's existing generating facilities, including facilities with closed-cycle re-circulating cooling systems (cooling towers). To address the rule's entrainment standards, facilities with once-through cooling systems may have to install cooling towers. New units constructed at existing plants would have to meet the national impingement standards and install closed-cycle cooling or the equivalent to meet the entrainment mandate. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of Alabama Power's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking cannot be determined at this time.

Alabama PSC Matters

Retail Fuel Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K for information regarding Alabama Power's fuel cost recovery. Alabama Power's under recovered fuel costs as of March 31, 2011 totaled $15 million as compared to $4 million at December 31, 2010. These under recovered fuel costs at March 31, 2011 are included in under recovered regulatory clause revenues and deferred under recovered regulatory clause revenues on Alabama Power's Condensed Balance Sheets herein. This classification is based on an estimate which includes such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Natural Disaster Reserve

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Natural Disaster Reserve" of Alabama Power in Item 7 and Note 3 to the financial statements under "Retail Regulatory Matters – Natural Disaster Reserve" in Item 8 of the Form 10-K for additional information.

On April 27, 2011, devastating storms swept through the central part of Alabama causing significant damage in parts of the service territory of Alabama Power. Over 400,000 of Alabama Power's 1.4 million customers were without electrical service immediately after the storms, resulting from significant damage to Alabama Power's transmission and distribution facilities. The preliminary estimated cost associated with repairing the damage to facilities and restoring electrical service to customers is between $40 million and $55 million for operations and maintenance expenses and between $180 million and $225 million for capital expenditures. Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to Alabama Power's transmission and distribution facilities.

At March 31, 2011, the NDR had an accumulated balance of $127 million, which is included in the Condensed Balance Sheets herein under other regulatory liabilities, deferred. The accruals are reflected as operations and maintenance expenses in the Condensed Statements of Income herein.

Income Tax Matters

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects to be placed in service in 2011). Additionally, in December 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 will have a positive impact on the future cash flows of Alabama Power. On March 29, 2011, the IRS issued additional guidance and safe harbors relating to the 50% and 100% bonus depreciation rules. Based on this guidance, Alabama Power estimates the potential increased cash flow for 2011 to be between approximately $100 million and $150 million. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Alabama Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Alabama Power is subject to certain claims and legal actions arising in the ordinary course of business. Alabama Power'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 Alabama Power cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Alabama Power in Item 8 of the Form 10-K, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on Alabama Power's financial statements.

The events in Japan have created uncertainties that may affect transportation of materials, price of fuels, availability of equipment from Japanese manufacturers, and future costs for operating nuclear plants. Specifically, the NRC plans to perform additional operational and safety reviews of existing nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. The ultimate outcome of these events cannot be determined at this time. See RISK FACTORS of Alabama Power in Item 1A of the Form 10-K for a discussion of certain risks associated with the operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world.

See the Notes to the Condensed Financial Statements herein for discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Alabama Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Alabama Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Alabama Power'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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Alabama Power in Item 7 of the Form 10-K for a complete discussion of Alabama Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, Unbilled Revenues, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Alabama Power's financial condition remained stable at March 31, 2011. Alabama Power 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.

Net cash provided from operating activities totaled $327 million for the first three months of 2011, an increase of $53 million as compared to the first three months of 2010. The increase in cash provided from operating activities was primarily due to accrued taxes related to refunds received from bonus depreciation and receivables. This is partially offset by a decrease in accounts payable associated with payables to affiliates, a decrease in net income, and the under collection of regulatory clause revenues. Net cash used for investing activities totaled $224 million for the first three months of 2011 primarily due to gross property additions related to steam generation equipment, nuclear fuel, and transmission and distribution expenditures. Net cash used for financing activities totaled $98 million for the first three months of 2011 primarily due to payment of common stock dividends and the issuance and maturity of senior notes. Fluctuations in cash flow from financing activities vary year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first three months of 2011 include decreases of $103 million in other accounts payable related to the timing of outstanding checks associated with property tax payments, $68 million in prepaid expenses related to income taxes, $43 million in unbilled revenues, and $41 million in customer accounts receivable; and increases of $60 million in property, plant, and equipment associated with nuclear fuel and routine property additions and $48 million in debt resulting from greater issuances than maturities.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Alabama Power in Item 7 of the Form 10-K for a description of Alabama Power's capital requirements for its construction program, scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, and trust funding requirements. There are no requirements through March 31, 2012 for maturities of long-term debt.

The approved construction program of Alabama Power includes a base level investment of $0.9 billion for 2011, $0.9 billion for 2012, and $1.1 billion for 2013. Included in Alabama Power's approved construction program are estimated environmental expenditures to comply with existing statutes and regulations of $47 million, $26 million, and $53 million for 2011, 2012, and 2013, respectively. Alabama Power currently anticipates that additional expenditures may be required to comply with anticipated statutes and regulations. Such additional expenditures are estimated to be in amounts up to $48 million, $108 million, and $354 million for 2011, 2012, and 2013, respectively. If the EPA's proposed

Utility MACT rule is finalized as proposed, Alabama Power estimates that the potential incremental investments in 2011 through 2013 for new environmental regulations will be close to the upper end of the estimates set forth above. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Sources of Capital

Alabama Power plans to obtain the funds required for construction and other purposes from sources similar to those utilized in the past. Alabama Power has primarily utilized funds from operating cash flows, unsecured debt, common stock, preferred stock, and preference stock. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Alabama Power in Item 7 of the Form 10-K for additional information.

Alabama Power's current liabilities sometimes exceed current assets because of Alabama Power's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. To meet short-term cash needs and contingencies, Alabama Power had at March 31, 2011 cash and cash equivalents of approximately $159 million and unused committed credit arrangements with banks of approximately $1.3 billion. Of the unused credit arrangements, $506 million expire in 2011 and $765 million expire in 2012. Of the credit arrangements that expire in 2011, $372 million contain provisions allowing for one-year term loans executable at expiration. Alabama Power expects to renew its credit arrangements, as needed, prior to expiration. The credit arrangements provide liquidity support to Alabama Power's commercial paper borrowings and $798 million are dedicated to funding purchase obligations related to variable rate pollution control revenue bonds. See Note 6 to the financial statements of Alabama Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information. Alabama Power 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 Alabama Power and other Southern Company subsidiaries. At March 31, 2011, Alabama Power had no commercial paper borrowings outstanding. During the first quarter 2011, Alabama Power had an average of $88 million of commercial paper outstanding at a weighted average interest rate of 0.2% per annum and the maximum amount outstanding was $255 million. Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Credit Rating Risk

Alabama Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At March 31, 2011, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $303 million. Included in these amounts are certain agreements that could require collateral in the event that one or more 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 Alabama Power's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

During the first quarter 2011, Alabama Power had interest rate swaps totaling $200 million expire, which did not materially increase market risk exposure relative to interest rate changes. Since a significant portion of outstanding indebtedness remains at fixed rates, Alabama Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Alabama Power continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to movements in electricity prices, Alabama Power enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. Alabama Power continues to manage a retail fuel-hedging program implemented per the guidelines of the Alabama PSC. As such, Alabama Power had no material change in market risk exposure for the first quarter 2011 when compared with the December 31, 2010 reporting period.

The changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, for the three months ended March 31, 2011 were as follows:

	First Quarter 2011 Changes
	Fair Value *(in millions)*
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(38)
Contracts realized or settled	11
Current period changes[(a)]	-
Contracts outstanding at the end of the period, assets (liabilities), net	$(27)

(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 three months ended March 31, 2011 was an increase of $11 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of mmBtu and prices of natural gas. At March 31, 2011, Alabama Power had a net hedge volume of 31.1 million mmBtu with a weighted average contract cost approximately $0.90 per mmBtu above market prices, compared to 33.9 million mmBtu at December 31, 2010 with a weighted average contract cost approximately $1.14 per mmBtu above market prices. The majority of the natural gas hedges are recovered through the fuel cost recovery clause.

Regulatory hedges relate to Alabama Power's fuel-hedging program where 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.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2011 and 2010 for energy-related derivative contracts that are not hedges were not material.

Alabama Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2011 were as follows:

	March 31, 2011 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ -	$ -	$ -	$-
Level 2	(27)	(23)	(4)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(27)	$(23)	$(4)	$-

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 Alabama Power. 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.

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Alabama Power in Item 7 and Note 1 under "Financial Instruments" and Note 11 to the financial statements of Alabama Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

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

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

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Alabama Power 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.

[This page intentionally left blank]

GEORGIA POWER COMPANY

GEORGIA POWER COMPANY

CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2011	2010
	(in millions)	
Operating Revenues:		
Retail revenues	**$ 1,815**	$ 1,792
Wholesale revenues, non-affiliates	**83**	110
Wholesale revenues, affiliates	**11**	14
Other revenues	**80**	68
Total operating revenues	**1,989**	1,984
Operating Expenses:		
Fuel	**677**	758
Purchased power, non-affiliates	**74**	82
Purchased power, affiliates	**163**	162
Other operations and maintenance	**422**	389
Depreciation and amortization	**173**	114
Taxes other than income taxes	**87**	80
Total operating expenses	**1,596**	1,585
Operating Income	**393**	399
Other Income and (Expense):		
Allowance for equity funds used during construction	**25**	35
Interest expense, net of amounts capitalized	**(96)**	(93)
Other income (expense), net	**(1)**	(6)
Total other income and (expense)	**(72)**	(64)
Earnings Before Income Taxes	**321**	335
Income taxes	**111**	93
Net Income	**210**	242
Dividends on Preferred and Preference Stock	**4**	4
Net Income After Dividends on Preferred and Preference Stock	**$ 206**	$ 238

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2011	2010
	(in millions)	
Net Income After Dividends on Preferred and Preference Stock	**$ 206**	$ 238
Other comprehensive income (loss):		
Qualifying hedges:		
Reclassification adjustment for amounts included in net income, net of tax of $1 and $2, respectively	**1**	3
Comprehensive Income	**$ 207**	$ 241

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2011	2010
	(in millions)	
Operating Activities:		
Net income	**$ 210**	$ 242
Adjustments to reconcile net income		
to net cash provided from operating activities --		
Depreciation and amortization, total	**210**	154
Deferred income taxes	**56**	59
Deferred revenues	**2**	(18)
Deferred expenses	**33**	25
Allowance for equity funds used during construction	**(25)**	(35)
Pension, postretirement, and other employee benefits	**(7)**	(4)
Stock based compensation expense	**4**	3
Storm damage accruals	**5**	5
Other, net	**(52)**	(26)
Changes in certain current assets and liabilities --		
-Receivables	**122**	(9)
-Fossil fuel stock	**(30)**	81
-Materials and supplies	**(9)**	1
-Prepaid income taxes	**80**	23
-Other current assets	**(4)**	(8)
-Accounts payable	**(50)**	(17)
-Accrued taxes	**(194)**	(185)
-Accrued compensation	**(65)**	(7)
-Other current liabilities	**64**	43
Net cash provided from operating activities	**350**	327
Investing Activities:		
Property additions	**(513)**	(625)
Nuclear decommissioning trust fund purchases	**(830)**	(199)
Nuclear decommissioning trust fund sales	**827**	150
Cost of removal, net of salvage	**1**	(14)
Change in construction payables, net of joint owner portion	**93**	41
Other investing activities	**(6)**	51
Net cash used for investing activities	**(428)**	(596)
Financing Activities:		
Decrease in notes payable, net	**(62)**	(81)
Proceeds --		
Capital contributions from parent company	**171**	460
Pollution control revenue bonds issuances	**137**	-
Senior notes issuances	**300**	350
Other long-term debt issuances	**250**	-
Redemptions --		
Pollution control revenue bonds	**(84)**	-
Senior notes	**(101)**	(250)
Other long-term debt	**(300)**	-
Payment of preferred and preference stock dividends	**(4)**	(4)
Payment of common stock dividends	**(224)**	(205)
Other financing activities	**(2)**	(2)
Net cash provided from financing activities	**81**	268
Net Change in Cash and Cash Equivalents	**3**	(1)
Cash and Cash Equivalents at Beginning of Period	**8**	14
Cash and Cash Equivalents at End of Period	**$ 11**	$ 13
49		
Cash paid during the period for --		
Interest (net of $9 and $13 capitalized for 2011 and 2010, respectively)	**$65**	$62
Income taxes (net of refunds)	**(77)**	(6)
Noncash transactions - accrued property additions at end of period	**350**	275

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	**At March 31, 2011**	At December 31, 2010
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 11**	$ 8
Receivables --		
Customer accounts receivable	**540**	580
Unbilled revenues	**160**	172
Under recovered regulatory clause revenues	**188**	184
Joint owner accounts receivable	**54**	60
Other accounts and notes receivable	**52**	67
Affiliated companies	**21**	21
Accumulated provision for uncollectible accounts	**(13)**	(11)
Fossil fuel stock, at average cost	**654**	624
Materials and supplies, at average cost	**380**	371
Vacation pay	**77**	78
Prepaid income taxes	**6**	99
Other regulatory assets, current	**107**	105
Other current assets	**66**	80
Total current assets	**2,303**	2,438
Property, Plant, and Equipment:		
In service	**26,681**	26,397
Less accumulated provision for depreciation	**10,008**	9,966
Plant in service, net of depreciation	**16,673**	16,431
Other utility plant, net	**67**	-
Nuclear fuel, at amortized cost	**421**	386
Construction work in progress	**3,304**	3,287
Total property, plant, and equipment	**20,465**	20,104
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**69**	70
Nuclear decommissioning trusts, at fair value	**791**	818
Miscellaneous property and investments	**40**	42
Total other property and investments	**900**	930
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**731**	723
Prepaid pension costs	**101**	91
Deferred under recovered regulatory clause revenues	**128**	214
Other regulatory assets, deferred	**1,224**	1,207
Other deferred charges and assets	**191**	207
Total deferred charges and other assets	**2,375**	2,442
Total Assets	**$ 26,043**	$ 25,914

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

49

Liabilities and Stockholder's Equity	**At March 31, 2011**	At December 31, 2010
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 379**	$ 415
Notes payable	**514**	576
Accounts payable --		
Affiliated	**200**	243
Other	**644**	574
Customer deposits	**198**	198
Accrued taxes --		
Accrued income taxes	**34**	1
Unrecognized tax benefits	**180**	187
Other accrued taxes	**95**	328
Accrued interest	**142**	94
Accrued vacation pay	**56**	58
Accrued compensation	**46**	109
Liabilities from risk management activities	**70**	77
Other cost of removal obligations, current	**31**	31
Nuclear decommissioning trust securities lending collateral	**100**	144
Other current liabilities	**162**	134
Total current liabilities	**2,851**	3,169
Long-term Debt	**8,169**	7,931
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,773**	3,718
Deferred credits related to income taxes	**127**	129
Accumulated deferred investment tax credits	**227**	229
Employee benefit obligations	**685**	684
Asset retirement obligations	**721**	705
Other cost of removal obligations	**128**	131
Other deferred credits and liabilities	**196**	211
Total deferred credits and other liabilities	**5,857**	5,807
Total Liabilities	**16,877**	16,907
Preferred Stock	**45**	45
Preference Stock	**221**	221
Common Stockholder's Equity:		
Common stock, without par value--		
Authorized - 20,000,000 shares		
Outstanding - 9,261,500 shares	**398**	398
Paid-in capital	**5,467**	5,291
Retained earnings	**3,045**	3,063
Accumulated other comprehensive loss	**(10)**	(11)
Total common stockholder's equity	**8,900**	8,741
Total Liabilities and Stockholder's Equity	**$ 26,043**	$ 25,914

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

FIRST QUARTER 2011 vs. FIRST QUARTER 2010

OVERVIEW

Georgia Power operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of Georgia Power'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, and fuel prices. Georgia Power is currently constructing two new nuclear and three new combined cycle generating units. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Georgia Power for the foreseeable future.

In December 2010, the Georgia PSC approved the 2010 ARP including a base rate increase of approximately $562 million effective January 1, 2011. On March 1, 2011, Georgia Power filed a request with the Georgia PSC to adjust its fuel cost recovery rates. The Georgia PSC will conduct public hearings on the fuel cost recovery filing in early May 2011, with a final decision expected on May 24, 2011. If approved, the new fuel cost recovery rates will go into effect June 1, 2011.

Georgia Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Georgia Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(32)	(13.4)

Georgia Power's net income after dividends on preferred and preference stock for the first quarter 2011 was $206 million compared to $238 million for the corresponding period in 2010. The decrease was primarily due to a decrease in the amortization of the regulatory liability related to other cost of removal obligations, an increase in operating and maintenance expenses, a decrease in revenue due to significantly colder weather in the first quarter 2010, and higher income taxes. This decrease was partially offset by an increase in retail base revenues effective January 1, 2011 as authorized by the Georgia PSC in the 2010 ARP.

Retail Revenues

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$23	1.3

Retail revenues for the first quarters 2011 and 2010 were $1.8 billion.

Details of the change to retail revenues are as follows:

	First Quarter 2011	
	(in millions)	*(% change)*
Retail – prior year	$1,792	
Estimated change in –		
Rates and pricing	141	7.9
Sales growth (decline)	(7)	(0.4)
Weather	(31)	(1.8)
Fuel cost recovery	(80)	(4.4)
Retail – current year	$1,815	1.3%

Revenues associated with changes in rates and pricing increased in the first quarter 2011 when compared to the corresponding period in 2010 due to the retail base rate increase and NCCR revenues.

Revenues attributable to changes in sales decreased in the first quarter 2011 when compared to the corresponding period in 2010. Weather-adjusted residential KWH sales decreased 0.2%, weather-adjusted commercial KWH sales decreased 1.8%, and weather-adjusted industrial KWH sales increased 3.5% in the first quarter 2011 when compared to the corresponding period in 2010.

Revenues resulting from changes in weather decreased in the first quarter 2011 when compared to the corresponding period in 2010 as a result of significantly colder weather in the first quarter 2010.

Fuel revenues and costs are allocated between retail and wholesale jurisdictions. Retail fuel cost recovery revenues decreased by $80 million in the first quarter of 2011 when compared to the corresponding period in 2010 due to decreased KWH sales and lower fuel costs.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power costs, and do not affect net income.

Wholesale Revenues – Non-Affiliates

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(27)	(24.5)

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

In the first quarter 2011, wholesale revenues from non-affiliates were $83 million compared to $110 million in the corresponding period in 2010, reflecting a $21 million decrease in energy revenues and a $6 million decrease in capacity revenues. The decrease in the first quarter 2011 was primarily due to a 27.4% decrease in KWH sales from lower demand resulting from significantly colder weather in the first quarter 2010 and the expiration of the long-term unit power sales contract in May 2010.

Other Revenues

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$12	17.6

In the first quarter 2011, other revenues were $80 million compared to $68 million in the corresponding period in 2010. This increase was primarily due to an $11 million increase in transmission revenues due to the increased usage of Georgia Power's transmission system by non-affiliated companies.

Fuel and Purchased Power Expenses

First Quarter 2011 vs. First Quarter 2010		
	(change in millions)	*(% change)*
Fuel*	$(81)	(10.7)
Purchased power – non-affiliates	(8)	(9.8)
Purchased power – affiliates	1	0.6
Total fuel and purchased power expenses	$(88)	

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

In the first quarter 2011, total fuel and purchased power expenses were $914 million compared to $1.0 billion in the corresponding period in 2010. The decrease was primarily due to a $34 million net decrease related to lower KWHs generated and purchased primarily due to lower customer demand as a result of significantly colder weather in 2010 and a $54 million decrease in the average cost of fuel and average price of purchased power.

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

Details of Georgia Power's cost of generation and purchased power are as follows:

Average Cost	First Quarter 2011	First Quarter 2010	Percent Change
	(cents per net KWH)		
Fuel	3.73	3.78	(1.3)
Purchased power	5.57	6.36	(12.4)

In the first quarter 2011, fuel expense was $677 million compared to $758 million in the corresponding period in 2010. This decrease was due to an 11.1% decrease of KWHs generated as a result of lower KWH demand and a 1.3% decrease in the average cost of fuel per KWH generated.

Non-Affiliates

In the first quarter 2011, purchased power expense from non-affiliates was $74 million compared to $82 million in the corresponding period in 2010. This decrease was due to a 29.9% decrease in the volume of KWHs purchased due to lower demand as a result of the significantly colder weather in first quarter 2010, partially offset by a 29.6% increase in the average cost per KWH purchased.

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

Other Operations and Maintenance Expenses

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$33	8.5

In the first quarter 2011, other operations and maintenance expenses were $422 million compared to $389 million in the corresponding period in 2010. This increase was primarily due to increases of $18 million in scheduled outages and maintenance at fossil generating plants, $7 million in transmission and distribution primarily due to maintenance of overhead lines, and $4 million in uncollectible account expense.

Depreciation and Amortization

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$59	51.8

In the first quarter 2011, depreciation and amortization was $173 million compared to $114 million in the corresponding period in 2010. This increase was primarily due to amortization of $10 million compared to $60 million in the first quarter 2011 and 2010, respectively, of the regulatory liability related to other cost of removal obligations as authorized by the Georgia PSC and depreciation on additional plant in service related to transmission, distribution, and environmental projects. See Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Rate Plans" in Item 8 of the Form 10-K for additional information on the other cost of removal regulatory liability.

Taxes Other Than Income Taxes

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$7	8.8

In the first quarter 2011, taxes other than income taxes were $87 million compared to $80 million in the corresponding period in 2010. This increase was primarily due to a $5 million increase in property tax in the first quarter 2011 compared to the corresponding period in 2010.

Allowance for Equity Funds Used During Construction

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(10)	(28.6)

In the first quarter 2011, AFUDC equity was $25 million compared to $35 million in the corresponding period in 2010. This decrease was due to the inclusion of Plant Vogtle Units 3 and 4 construction work in progress in rate base effective January 1, 2011, which reduced the amount of AFUDC capitalized. See Note 3 to the financial statements of Georgia Power under "Construction – Nuclear" in Item 8 of the Form 10-K, Note (B) to the Condensed Financial Statements herein under "State PSC Matters – Georgia Power – Nuclear Construction," and FUTURE EARNINGS POTENTIAL – "Construction – Nuclear" herein for additional information.

Income Taxes

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$18	19.4

In the first quarter 2011, income taxes were $111 million compared to $93 million in the corresponding period in 2010. The increase in income taxes was primarily due to the recognition in the first quarter 2010 of certain state income tax credits that remain subject to litigation and a decrease in non-taxable AFUDC equity in the first quarter 2011, partially offset by lower pre-tax earnings. See Notes 3 and 5 to the financial statements of Georgia Power under "Income Tax Matters" and "Unrecognized Tax Benefits," respectively, in Item 8 of the Form 10-K and Notes (B) and (G) to the Condensed Financial Statements herein under "Income Tax Matters – Georgia State Income Tax Credits" and "Unrecognized Tax Benefits," respectively, for additional information.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Georgia Power's future earnings potential. The level of Georgia Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Georgia Power's business of selling electricity. These factors include Georgia Power'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 Georgia Power's service area. Changes in economic conditions impact sales for Georgia Power 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. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Georgia Power in Item 7 of the Form 10-K.

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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Carbon Dioxide Litigation

Kivalina Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" in Item 8 of the Form 10-K for additional information regarding carbon dioxide litigation. On February 23, 2011, the U.S. Court of Appeals for the Ninth Circuit issued an order staying the case until June 15, 2011. The ultimate outcome of this matter cannot be determined at this time.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Georgia Power in Item 7 of the Form 10-K for additional information regarding regulation of air quality. On May 3, 2011, the EPA published a proposed rule, called Utility MACT (Maximum Achievable Control Technology), which would impose stringent emission limits on coal- and oil-fired electric utility steam generating units (EGUs). The proposed rule establishes numeric emission limits for acid gases, mercury, and total particulate matter. Meeting the proposed limits would likely require additional emission control equipment such as scrubbers, SCRs, baghouses, and other control measures at many coal-fired EGUs. Pursuant to a court-approved consent decree, the EPA must issue a final rule by November 16, 2011. Compliance for existing sources would be required three years after the effective date of the final rule. In the proposed rule, the EPA discussed the possibility of a one-year compliance extension which could be granted by the EPA or the states on a case-by-case basis if necessary. If finalized as proposed, compliance with this rule would require significant capital expenditures and compliance costs at many of Georgia Power's facilities which could impact unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be impacted if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the proposed rule within the proposed compliance period, and the limited compliance period could negatively impact electric system reliability. The outcome of this rulemaking cannot be determined at this time.

In April 2010, the EPA proposed an Industrial Boiler MACT rule that would establish emissions limits for various hazardous air pollutants typically emitted from industrial boilers, including biomass boilers and start-up boilers. The EPA issued the final rules on February 23, 2011 and, at the same time, issued a notice of intent to reconsider the final rules to allow for additional public review and comment. Georgia Power has delayed the decision to convert Plant Mitchell Unit 3 to biomass until there is greater clarity regarding these regulations. The impact of these regulations will depend on their final form and the outcome of any legal challenges and cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Georgia Power in Item 7 of the Form 10-K for additional information regarding regulation of water quality. On April 20, 2011, the EPA proposed a rule that establishes standards for reducing impacts to fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. The rule focuses on reducing adverse impacts to fish and other aquatic life due to impingement (when fish and other aquatic life are trapped by water flow velocity against a facility's cooling water intake structure screens) and entrainment (when aquatic organisms are drawn through a facility's cooling water system after entering through the cooling water intake structure). Affected cooling water intake structures would have to comply with national impingement standards (for intake velocity or alternatively numeric impingement reduction standards) and entrainment reduction requirements (determined on a case-by-case basis). The rule's proposed impingement standards could require technological improvements to cooling water intake structures at many of Georgia Power's existing generating facilities, including facilities with closed-cycle re-circulating cooling systems (cooling towers). To address the rule's entrainment standards, facilities with once-through cooling systems may have to install cooling towers. New units constructed at existing plants would have to meet the national impingement standards and install closed-cycle cooling or the equivalent to meet the entrainment mandate. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of Georgia Power's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking cannot be determined at this time.

Georgia PSC Matters

Fuel Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information. As of March 31, 2011, Georgia Power had a total under recovered fuel cost balance of approximately $313 million compared to $398 million at December 31, 2010. Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, any changes in the billing factor will not have a significant effect on Georgia Power's revenues or net income, but will affect cash flow.

On March 1, 2011, Georgia Power filed a request with the Georgia PSC to decrease fuel rates by 0.61%. The decrease would reduce Georgia Power's annual billings by approximately $43 million. The decrease in fuel costs is driven primarily by lower natural gas prices than those included in current rates as a result of increases in natural gas supplies from the production of shale gas and lower industrial demand. If approved, the new rates will go into effect June 1, 2011. The ultimate outcome of this matter cannot be determined at this time.

Plant Branch Units 1 and 2 De-certification

See "Environmental Matters – Air Quality" and "– Water Quality" herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Byproducts" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Rate Plans" in Item 8 of the Form 10-K for additional information regarding potential rules and regulations being developed by the EPA, including the Utility MACT rule for coal- and oil-fired EGUs, revisions to effluent guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; Georgia Power's analysis of the potential costs and benefits of installing the required controls on its coal-fired generating units in light of these regulations; and the 2010 ARP.

On March 22, 2011, the board of the Georgia Department of Natural Resources began consideration of modifications to the Georgia Multi-Pollutant Rule. The proposed modifications would change the compliance dates for certain of Georgia Power's coal-fired generating units as follows:

Scherer 3	July 1, 2011
Branch 1	December 31, 2013
Branch 2	October 1, 2013
Branch 3	October 1, 2015
Branch 4	December 31, 2015

The Multi-Pollutant Rule is designed to reduce emissions of mercury, sulfur dioxide, and nitrogen oxides statewide. The Utility MACT rule will also regulate emissions of mercury, in addition to other air pollutants. All required controls, including SCR, scrubber, and baghouse, are expected to be operational at Plant Scherer Unit 3 by the required compliance date. As a result of these proposed rules, Georgia Power's management expects to request that the Georgia PSC approve de-certification of its Plant Branch Units 1 and 2, totaling 569 MWs of capacity, as of the effective dates for controls under the Multi-Pollutant Rule as revised. Georgia Power continues to analyze the potential costs and benefits of installing the required controls on its remaining coal-fired units, including Plant Branch Units 3 and 4, in light of the proposed air quality rules, as well as additional potential federal regulations related to water quality and coal combustion byproducts. Georgia Power may determine that retiring and replacing certain of its existing units with new generating resources or purchased power is more economically efficient than installing the required controls.

Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated integrated resource plan will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. Georgia Power currently expects to file an update to its integrated resource plan in late summer 2011, which would include the Plant Branch Units 1 and 2 de-certification request. In connection with this filing, Georgia Power expects to request the Georgia PSC to approve the deferral and related amortization of the retail portion of the related costs associated with the de-certification request. Georgia Power moved the retail portion of the net carrying value of Plant Branch Units 1 and 2 from plant in service, net of depreciation, to other utility plant, net of depreciation. Consistent with current ratemaking treatment, Georgia Power will continue to depreciate these units using the composite straight-line rates approved by the Georgia PSC, and upon actual retirement, expects to include the units' remaining net carrying value in rate base. However, the recovery periods for these units may change in connection with Georgia Power's updated integrated resource plan. As a result of this regulatory treatment, the de-certification of Plant Branch Units 1 and 2 is not expected to have a significant impact on Georgia Power's financial statements.

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

Storm Damage Reserve

During April 2011, severe storms in Georgia caused significant damage to Georgia Power's distribution and transmission facilities. Georgia Power maintains a reserve for property damage to cover the operating and maintenance cost of damages from major storms to its transmission and distribution lines as mandated by the Georgia PSC. As a result of this regulatory treatment, the storms are not expected to have a material impact on Georgia Power's financial statements. See Note 1 to the financial statements of Georgia Power under "Storm Damage Reserve" in Item 8 of the Form 10-K for additional information.

Income Tax Matters

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects to be placed in service in 2011). Additionally, in December 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 will have a positive impact on the future cash flows of Georgia Power. On March 29, 2011, the IRS issued additional guidance and safe harbors relating to the 50% and 100% bonus depreciation rules. Based on this guidance, Georgia Power estimates the potential increased cash flow for 2011 to be between approximately $200 million and $275 million. The ultimate outcome of this matter cannot be determined at this time.

Construction

Nuclear

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Construction – Nuclear" of Georgia Power in Item 7 of the Form 10-K for information regarding the construction of Plant Vogtle Units 3 and 4.

In December 2010, Westinghouse submitted an AP1000 Design Certification Amendment (DCA) to the NRC. On February 10, 2011, the NRC announced that it was seeking public comment on a proposed rule to approve the DCA and amend the certified AP1000 reactor design for use in the U.S. The Advisory Committee on Reactor Safeguards also issued a letter on January 24, 2011 endorsing the issuance of the Construction and Operating License (COL) for Plant Vogtle Units 3 and 4. In addition, on March 25, 2011, the NRC submitted to the EPA the final environmental impact statement for Plant Vogtle Units 3 and 4. Georgia Power currently expects to receive the COL for Plant Vogtle Units 3 and 4 from the NRC in late 2011 based on the NRC's February 16, 2011 release of its COL schedule framework.

On February 21, 2011, the Georgia PSC voted to approve Georgia Power's third semi-annual construction monitoring report including total costs of $1.048 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2010. In connection with its certification of Plant Vogtle Units 3 and 4, the Georgia PSC ordered Georgia Power and the PSC Staff to work together to develop a risk sharing or incentive mechanism that would provide some level of protection to ratepayers in the event of significant cost overruns, but also not penalize Georgia Power's earnings if and when overruns are due to mandates from governing agencies. Such discussions have continued through the third semi-annual construction monitoring proceedings; however, the Georgia PSC has deferred a decision with respect to any related risk-sharing or incentive mechanism. A Georgia PSC hearing on this matter is scheduled on July 6, 2011 and a decision is expected on August 2, 2011. Georgia Power will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In December 2010, the Georgia PSC approved the NCCR tariff, which became effective January 1, 2011. The NCCR tariff was established to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period in accordance with the Georgia Nuclear Energy Financing Act. With respect to Plant Vogtle Units 3 and 4, this legislation allows Georgia Power to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. Georgia Power is collecting and amortizing to earnings approximately $91 million of financing costs capitalized in 2009 and 2010 over the five-year period ending December 31, 2015 in addition to the ongoing financing costs. At March 31, 2011, approximately $87 million of these 2009 and 2010 costs are included in construction work in progress.

Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), and a consortium consisting of Westinghouse and Stone & Webster, Inc. have established both informal and formal dispute resolution procedures in order to resolve issues that commonly arise during the course of constructing a project of this magnitude. Southern Nuclear, on behalf of the Owners, has initiated both formal and informal claims through these procedures, including ongoing claims, and anticipates that further issues are likely to arise in the future. The Owners have successfully used both the informal and formal procedures to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

On March 11, 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. According to published reports, the owner of these units is continuing work to stabilize these units following a loss of operation of the cooling systems for the units. While Georgia Power will continue to monitor this developing situation, it has not identified any immediate impact to the licensing and construction of Plant Vogtle Units 3 and 4 or the operation of its existing nuclear generating units.

The events in Japan have created uncertainties that may affect transportation, price of fuels, availability of equipment from Japanese manufacturers, and future costs for operating nuclear plants. Specifically, the NRC plans to perform additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements.

See RISK FACTORS of Georgia Power in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world.

There are other pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, including petitions filed at the NRC in response to the events in Japan. Similar additional challenges at the state and federal level are expected as construction proceeds.

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

Other Construction

In May 2010, the Georgia PSC approved Georgia Power's request to extend the construction schedule for Plant McDonough Units 4, 5, and 6 as a result of the short-term reduction in forecasted demand, as well as the requested increase in the certified amount. As a result, the units are expected to be placed into service in January 2012, May 2012, and January 2013, respectively. The Georgia PSC has approved Georgia Power's quarterly construction monitoring reports, including actual project expenditures incurred, through June 30, 2010. Georgia Power will continue to file quarterly construction monitoring reports throughout the construction period.

Other Matters

Georgia Power is involved in various other matters being litigated, regulatory matters, and certain tax-related issues that could affect future earnings. In addition, Georgia Power is subject to certain claims and legal actions arising in the ordinary course of business. Georgia Power'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 Georgia Power cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Georgia Power in Item 8 of the Form 10-K, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on Georgia Power's financial statements.

See the Notes to the Condensed Financial Statements herein for discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Georgia Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Georgia Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Georgia Power'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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Georgia Power in Item 7 of the Form 10-K for a complete discussion of Georgia Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, Unbilled Revenues, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Georgia Power's financial condition remained stable at March 31, 2011. Georgia Power 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.

Net cash provided from operating activities totaled $350 million for the first three months of 2011, compared to $327 million for the corresponding period in 2010. The $23 million increase is primarily due to higher recovery of fuel costs. Net cash used for investing activities totaled $428 million primarily due to gross property additions to utility plant in the first three months of 2011. Net cash provided from financing activities totaled $81 million for the first three months of 2011, compared to $268 million for the corresponding period in 2010. The $187 million decrease is primarily due to higher capital contributions from Southern Company in the first quarter 2010, partially offset by long-term debt issuances in the first quarter 2011.

Significant balance sheet changes for the first three months of 2011 include an increase of $361 million in total property, plant, and equipment, an increase of $238 million in long-term debt to replace short-term debt and provide funds for Georgia Power's continuous construction program, and an increase in paid in capital of $176 million reflecting equity contributions from Southern Company.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Georgia Power in Item 7 of the Form 10-K for a description of Georgia Power's capital requirements for its construction program, scheduled maturities of long-term debt, as well as related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, trust funding requirements, and unrecognized tax benefits. Approximately $379 million will be required through March 31, 2012 to fund maturities and announced repurchases of long-term debt.

The construction program of Georgia Power is currently estimated to include a base level investment of $2.1 billion, $2.2 billion, and $2.0 billion for 2011, 2012, and 2013, respectively. Included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $73 million, $79 million, and $58 million for 2011, 2012, and 2013, respectively. In addition, Georgia Power currently estimates that potential incremental investments to comply with anticipated new environmental regulations could range from $69 million to $289 million for 2011, $191 million to $651 million for 2012, and $476 million to $1.4 billion for 2013. If the EPA's proposed Utility MACT rule is finalized as proposed, Georgia Power estimates that the potential incremental investments in 2011 through 2013 for new environmental regulations will be closer to the upper end of the ranges set forth above. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Sources of Capital

Except as described below with respect to potential DOE loan guarantees, Georgia Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company.

However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Georgia Power in Item 7 of the Form 10-K for additional information.

In June 2010, Georgia Power reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future borrowings by Georgia Power related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to Georgia Power and secured by a first priority lien on Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs or approximately $3.4 billion and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to receipt of the COL for Plant Vogtle Units 3 and 4 from the NRC, negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. There can be no assurance that the DOE will issue loan guarantees for Georgia Power. See FUTURE EARNINGS POTENTIAL – "Construction – Nuclear" herein for more information on Plant Vogtle Units 3 and 4.

Georgia Power'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, Georgia Power had at March 31, 2011 approximately $11 million of cash and cash equivalents and approximately $1.7 billion of unused committed credit arrangements with banks. As of March 31, 2011, of the unused credit arrangements, $595 million expire in 2011 and $1.1 billion expire in 2012. Of the credit arrangements that expire in 2011 and 2012, $40 million contain provisions allowing for two-year term loans executable at expiration and $220 million contain provisions allowing for one-year term loans executable at expiration. Georgia Power expects to renew its credit arrangements, as needed, prior to expiration. At March 31, 2011, the credit arrangements were dedicated to providing liquidity support to Georgia Power's commercial paper program and approximately $522 million of purchase obligations related to variable rate pollution control revenue bonds. See Note 6 to the financial statements of Georgia Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information. Georgia Power 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 Georgia Power and other Southern Company subsidiaries. At March 31, 2011, Georgia Power had approximately $513 million of commercial paper borrowings outstanding with a weighted average interest rate of 0.3% per annum. During the first quarter 2011, the maximum amount of commercial paper outstanding was $681 million and the average amount outstanding was $330 million. The weighted average annual interest rate on commercial paper in the first quarter 2011 was 0.3%. Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Credit Rating Risk

Georgia Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, and construction of new generation. At March 31, 2011, the maximum potential collateral requirements under these contracts at a BBB- and/or Baa3 rating were approximately $27 million. At March 31, 2011, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $1.4 billion. Included in these amounts are certain agreements that could require collateral in the event that one or more 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 Georgia Power's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Georgia Power's market risk exposure relative to interest rate changes for the first quarter 2011 has not changed materially compared with the December 31, 2010 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, Georgia Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Georgia Power continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to movements in electricity prices, Georgia Power enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. Georgia Power continues to manage a fuel-hedging program implemented per the guidelines of the Georgia PSC. As such, Georgia Power had no material change in market risk exposure for the first quarter 2011 relative to fuel and electricity prices when compared with the December 31, 2010 reporting period.

The changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, for the three months ended March 31, 2011 were as follows:

	First Quarter 2011 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(100)
Contracts realized or settled	17
Current period changes[(a)]	(1)
Contracts outstanding at the end of the period, assets (liabilities), net	$ (84)

(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 three months ended March 31, 2011 was an increase of $16 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of mmBtu and prices of natural gas. At March 31, 2011, Georgia Power had a net hedge volume of 65.0 million mmBtu with a weighted average contract cost approximately $1.38 per mmBtu above market prices, compared to 58.7 million mmBtu at December 31, 2010 with a weighted average contract cost approximately $1.74 per mmBtu above market prices. The natural gas hedges are recovered through the fuel cost recovery mechanism.

Regulatory hedges relate to Georgia Power's fuel-hedging program where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2011 and 2010 for energy-related derivative contracts that are not hedges were not material.

Georgia Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2011 were as follows:

	March 31, 2011 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ -	$ -	$ -	$-
Level 2	(84)	(70)	(14)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(84)	$(70)	$(14)	$-

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 Georgia Power. 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.

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Georgia Power in Item 7 and Note 1 under "Financial Instruments" and Note 11 to the financial statements of Georgia Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

In January 2011, Georgia Power's $100 million aggregate principal amount of Series S 4.0% Senior Notes due January 15, 2011 matured.

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

In March 2011, Georgia Power's $300 million variable rate bank term loan due on March 4, 2011 matured and was partially replaced by two one-year $125 million aggregate principal amount variable rate bank loans that bear interest based on one-month LIBOR.

Subsequent to March 31, 2011, Georgia Power issued $250 million aggregate principal amount of Series 2011B 3.0% Senior Notes due April 15, 2016. The proceeds were used to repay short-term debt and for general corporate purposes, including Georgia Power's continuous construction program.

Also subsequent to March 31, 2011, Georgia Power purchased and is holding $113.5 million of pollution control revenue bonds. The bonds are expected to be remarketed to investors at a future date.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Georgia Power 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.

[This page intentionally left blank]

GULF POWER COMPANY

GULF POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2011	2010
	(in thousands)	
Operating Revenues:		
Retail revenues	**$ 274,826**	$ 304,750
Wholesale revenues, non-affiliates	**31,019**	27,914
Wholesale revenues, affiliates	**4,135**	9,518
Other revenues	**14,628**	14,530
Total operating revenues	**324,608**	356,712
Operating Expenses:		
Fuel	**131,782**	152,712
Purchased power, non-affiliates	**7,003**	7,435
Purchased power, affiliates	**16,618**	20,413
Other operations and maintenance	**80,509**	70,418
Depreciation and amortization	**31,756**	28,071
Taxes other than income taxes	**24,896**	25,233
Total operating expenses	**292,564**	304,282
Operating Income	**32,044**	52,430
Other Income and (Expense):		
Allowance for equity funds used during construction	**2,135**	1,385
Interest income	**14**	17
Interest expense, net of amounts capitalized	**(13,629)**	(11,385)
Other income (expense), net	**(563)**	(533)
Total other income and (expense)	**(12,043)**	(10,516)
Earnings Before Income Taxes	**20,001**	41,914
Income taxes	**6,759**	15,063
Net Income	**13,242**	26,851
Dividends on Preference Stock	**1,551**	1,551
Net Income After Dividends on Preference Stock	**$ 11,691**	$ 25,300

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2011	2010
	(in thousands)	
Net Income After Dividends on Preference Stock	**$ 11,691**	$ 25,300
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $- and $(953), respectively	**-**	(1,518)
Reclassification adjustment for amounts included in net income, net of tax of $90 and $105, respectively	**143**	166
Total other comprehensive income (loss)	**143**	(1,352)
Comprehensive Income	**$ 11,834**	$ 23,948

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Operating Activities:		
Net income	**$ 13,242**	$ 26,851
Adjustments to reconcile net income		
to net cash provided from operating activities --		
Depreciation and amortization, total	**33,294**	29,659
Deferred income taxes	**6,249**	2,917
Allowance for equity funds used during construction	**(2,135)**	(1,385)
Pension, postretirement, and other employee benefits	**(1,256)**	550
Stock based compensation expense	**518**	623
Other, net	**(3,793)**	(520)
Changes in certain current assets and liabilities --		
-Receivables	**35,336**	6,150
-Prepayments	**1,156**	983
-Fossil fuel stock	**(14,941)**	17,419
-Materials and supplies	**(726)**	(1,170)
-Prepaid income taxes	**28,889**	4,530
-Property damage cost recovery	**-**	11
-Other current assets	**7**	12
-Accounts payable	**(8,863)**	(4,443)
-Accrued taxes	**4,053**	15,539
-Accrued compensation	**(10,000)**	(3,462)
-Other current liabilities	**6,127**	6,304
Net cash provided from operating activities	**87,157**	100,568
Investing Activities:		
Property additions	**(94,239)**	(81,225)
Distribution of restricted cash from pollution control revenue bonds	**-**	2,340
Cost of removal, net of salvage	**(5,314)**	(5,759)
Change in construction payables	**3,171**	(11,846)
Payments pursuant to long-term service agreements	**(2,198)**	(699)
Other investing activities	**68**	(190)
Net cash used for investing activities	**(98,512)**	(97,379)
Financing Activities:		
Decrease in notes payable, net	**(6,620)**	(6,599)
Proceeds --		
Common stock issued to parent	**50,000**	50,000
Capital contributions from parent company	**809**	1,128
Redemptions --		
Senior notes	**(125)**	(85)
Payment of preference stock dividends	**(1,551)**	(1,551)
Payment of common stock dividends	**(27,500)**	(26,075)
Other financing activities	**110**	605
Net cash provided from financing activities	**15,123**	17,423
Net Change in Cash and Cash Equivalents	**3,768**	20,612
Cash and Cash Equivalents at Beginning of Period	**16,434**	8,677
Cash and Cash Equivalents at End of Period	**$ 20,202**	$ 29,289
Supplemental Cash Flow Information:		
Cash paid during the period for --		
Interest (net of $851 and $552 capitalized for 2011 and 2010, respectively)	**$8,284**	$9,461
Income taxes (net of refunds)	**(29,557)**	(4,383)
Noncash transactions - accrued property additions at end of period	**17,882**	32,308

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	**At March 31, 2011**	At December 31, 2010
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 20,202**	$ 16,434
Receivables --		
Customer accounts receivable	**58,954**	74,377
Unbilled revenues	**44,970**	64,697
Under recovered regulatory clause revenues	**22,077**	19,690
Other accounts and notes receivable	**10,253**	9,867
Affiliated companies	**4,923**	7,859
Accumulated provision for uncollectible accounts	**(1,518)**	(2,014)
Fossil fuel stock, at average cost	**182,096**	167,155
Materials and supplies, at average cost	**45,455**	44,729
Other regulatory assets, current	**16,849**	20,278
Prepaid expenses	**25,937**	58,412
Other current assets	**3,259**	3,585
Total current assets	**433,457**	485,069
Property, Plant, and Equipment:		
In service	**3,738,908**	3,634,255
Less accumulated provision for depreciation	**1,087,442**	1,069,006
Plant in service, net of depreciation	**2,651,466**	2,565,249
Construction work in progress	**200,079**	209,808
Total property, plant, and equipment	**2,851,545**	2,775,057
Other Property and Investments	**16,284**	16,352
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**49,920**	46,357
Prepaid pension costs	**7,998**	7,291
Other regulatory assets, deferred	**237,448**	219,877
Other deferred charges and assets	**29,288**	34,936
Total deferred charges and other assets	**324,654**	308,461
Total Assets	**$3,625,940**	$3,584,939

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At March 31, 2011**	At December 31, 2010
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 110,000**	$ 110,000
Notes payable	**86,563**	93,183
Accounts payable --		
Affiliated	**39,567**	46,342
Other	**67,856**	68,840
Customer deposits	**35,914**	35,600
Accrued taxes --		
Accrued income taxes	**4,613**	3,835
Other accrued taxes	**11,754**	7,944
Accrued interest	**18,530**	13,393
Accrued compensation	**6,234**	14,459
Other regulatory liabilities, current	**22,860**	27,060
Liabilities from risk management activities	**7,167**	9,415
Other current liabilities	**18,863**	19,766
Total current liabilities	**429,921**	449,837
Long-term Debt	**1,114,406**	1,114,398
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**396,377**	382,876
Accumulated deferred investment tax credits	**7,771**	8,109
Employee benefit obligations	**75,472**	76,654
Other cost of removal obligations	**205,373**	204,408
Other regulatory liabilities, deferred	**42,378**	42,915
Other deferred credits and liabilities	**145,382**	132,708
Total deferred credits and other liabilities	**872,753**	847,670
Total Liabilities	**2,417,080**	2,411,905
Preference Stock	**97,998**	97,998
Common Stockholder's Equity:		
Common stock, without par value--		
Authorized - 20,000,000 shares		
Outstanding - March 31, 2011: 4,142,717 shares		
- December 31, 2010: 3,642,717 shares	**353,060**	303,060
Paid-in capital	**539,867**	538,375
Retained earnings	**220,519**	236,328
Accumulated other comprehensive loss	**(2,584)**	(2,727)
Total common stockholder's equity	**1,110,862**	1,075,036
Total Liabilities and Stockholder's Equity	**$3,625,940**	$3,584,939

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

FIRST QUARTER 2011 vs. FIRST QUARTER 2010

OVERVIEW

Gulf Power 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 Gulf Power'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 Gulf Power for the foreseeable future.

Gulf Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Gulf Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(13.6)	(53.8)

Gulf Power's net income after dividends on preference stock for the first quarter 2011 was $11.7 million compared to $25.3 million for the corresponding period in 2010. The decrease was primarily due to increases in other operations and maintenance expenses in the first quarter 2011 and significantly colder weather in the first quarter 2010.

Retail Revenues

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(29.9)	(9.8)

In the first quarter 2011, retail revenues were $274.8 million compared to $304.7 million for the corresponding period in 2010.

Details of the change to retail revenues are as follows:

	First Quarter 2011	
	(in millions)	*(% change)*
Retail – prior year	$304.7	
Estimated change in –		
Rates and pricing	(2.0)	(0.7)
Sales growth (decline)	1.2	0.4
Weather	(9.5)	(3.1)
Fuel and other cost recovery	(19.6)	(6.4)
Retail – current year	$274.8	(9.8)%

Revenues associated with changes in rates and pricing decreased in the first quarter 2011 when compared to the corresponding period in 2010 primarily due to lower recoverable costs under Gulf Power's environmental cost recovery clause due to lower KWH energy sales.

Annually, Gulf Power petitions the Florida PSC for recovery of projected environmental compliance costs including any true-up amount from prior periods, and approved rates are implemented each January. These recovery provisions include related expenses and a return on average net investment. See Note 1 to the financial statements of Gulf Power under "Revenues" and Note 3 to the financial statements of Gulf Power under "Environmental Matters – Environmental Remediation" and "Retail Regulatory Matters – Environmental Cost Recovery" in Item 8 of the Form 10-K for additional information.

Revenues attributable to changes in sales increased in the first quarter 2011 when compared to the corresponding period in 2010. Weather-adjusted KWH energy sales to residential and commercial customers increased 2.0% and 2.2%, respectively, due to higher use per customer. KWH energy sales to industrial customers increased 7.9% primarily due to the addition of a new large customer and several customers buying more energy during maintenance outages of the customers' onsite generation facilities.

Revenues attributable to changes in weather decreased in the first quarter 2011 when compared to the corresponding period for 2010 due to significantly colder weather in the first quarter 2010.

Fuel and other cost recovery revenues decreased in the first quarter 2011 when compared to the corresponding period for 2010 primarily due to lower fuel cost for generation and lower purchased power energy cost required to meet a lower level of KWH energy sales. Fuel and other cost recovery revenues include fuel expenses, the energy component of purchased power costs, and purchased power capacity costs. Annually, Gulf Power petitions the Florida PSC for recovery of projected fuel and purchased power costs including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on net income. See FUTURE EARNINGS POTENTIAL – "Florida PSC Matters – Fuel Cost Recovery" herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Gulf Power in Item 7 and Note 1 to the financial statements of Gulf Power under "Revenues" and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information.

Wholesale Revenues – Non-Affiliates

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$3.1	11.1

Wholesale revenues from non-affiliates will vary depending on fuel prices, the market cost of available energy compared to the cost of Gulf Power and Southern Company system-owned generation, demand for energy within the Southern Company service territory, and availability of Southern Company system generation. Wholesale revenues from non-affiliates are predominantly unit power sales under long-term contracts to other Florida and Georgia utilities. Revenues from these contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment under the contracts. Energy is generally sold at variable cost.

In the first quarter 2011, wholesale revenues from non-affiliates were $31.0 million compared to $27.9 million for the corresponding period in 2010. The increase was primarily due to increased capacity revenues as a result of contracts effective in the second quarter 2010.

Wholesale Revenues – Affiliates

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(5.4)	(56.6)

Wholesale revenues from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost.

In the first quarter 2011, wholesale revenues from affiliates were $4.1 million compared to $9.5 million for the corresponding period in 2010. The decrease was primarily due to a 43.7% decrease in price related to lower energy rates in the first quarter 2011 and decreased energy revenues related to a 22.9% decrease in KWH energy sales due to decreases in customer demand.

Fuel and Purchased Power Expenses

First Quarter 2011 vs. First Quarter 2010		
	(change in millions)	*(% change)*
Fuel*	$(21.0)	(13.7)
Purchased power – non-affiliates	(0.4)	(5.8)
Purchased power – affiliates	(3.8)	(18.6)
Total fuel and purchased power expenses	$(25.2)	

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

In the first quarter 2011, total fuel and purchased power expenses were $155.4 million compared to $180.6 million for the corresponding period in 2010. The decrease in fuel and purchased power expenses was due to a $12.7 million decrease in the average cost of fuel and purchased power and a $12.5 million decrease related to total KWHs generated and purchased.

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

Details of Gulf Power's cost of generation and purchased power are as follows:

Average Cost	First Quarter 2011	First Quarter 2010	Percent Change
	(cents per net KWH)		
Fuel	4.69	5.11	(8.22)
Purchased power	5.37	5.56	(3.42)

In the first quarter 2011, fuel expense was $131.8 million compared to $152.7 million for the corresponding period in 2010. The decrease was primarily due to a 45.3% decrease in the average cost of natural gas and a 1.7% decrease in KWHs generated as a result of decreased demand, partially offset by a 2.4% increase in the average cost of coal.

Non-Affiliates

In the first quarter 2011, purchased power expense from non-affiliates was $7.0 million compared to $7.4 million for the corresponding period in 2010. The decrease was primarily due to a 56.3% decrease in the volume of KWHs purchased, partially offset by an 18.3% increase in average cost per KWH purchased.

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

Affiliates

In the first quarter 2011, purchased power expense from affiliates was $16.6 million compared to $20.4 million for the corresponding period in 2010. The decrease was primarily due to a 3.4% decrease in average cost per KWH purchased and a 16.5% decrease in the volume of KWHs purchased related to decreases in customer demand.

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

Other Operations and Maintenance Expenses

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$10.1	14.3

In the first quarter 2011, other operations and maintenance expenses were $80.5 million compared to $70.4 million for the corresponding period in 2010. The increase was primarily due to planned outage maintenance expenses at Plant Crist.

Depreciation and Amortization

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$3.7	13.1

In the first quarter 2011, depreciation and amortization was $31.8 million compared to $28.1 million for the corresponding period in 2010. The increase was primarily due to the addition of environmental control projects and other net additions to transmission and distribution facilities.

Allowance for Equity Funds Used During Construction

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$0.7	54.2

In the first quarter 2011, AFUDC equity was $2.1 million compared to $1.4 million for the corresponding period in 2010. The increase was primarily due to construction of environmental control projects.

Interest Expense, Net of Amounts Capitalized

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$2.2	19.7

In the first quarter 2011, interest expense, net of amounts capitalized was $13.6 million compared to $11.4 million for the corresponding period in 2010. The increase was primarily due to an increase in long-term debt resulting from the issuance of additional senior notes.

Income Taxes

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(8.3)	(55.1)

In the first quarter 2011, income taxes were $6.8 million compared to $15.1 million for the corresponding period in 2010. The decrease was primarily due to lower pre-tax earnings.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Gulf Power's future earnings potential. The level of Gulf Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Gulf Power's business of selling electricity. These factors include Gulf Power'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 Gulf Power's service area. Changes in economic conditions impact sales for Gulf Power, 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. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Gulf Power in Item 7 of the Form 10-K.

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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Carbon Dioxide Litigation

Kivalina Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" in Item 8 of the Form 10-K for additional information regarding carbon dioxide litigation. On February 23, 2011, the U.S. Court of Appeals for the Ninth Circuit issued an order staying the case until June 15, 2011. The ultimate outcome of this matter cannot be determined at this time.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Gulf Power in Item 7 of the Form 10-K for additional information regarding regulation of air quality. On May 3, 2011, the EPA published a proposed rule, called Utility MACT (Maximum Achievable Control Technology), which would impose stringent emission limits on coal- and oil-fired electric utility steam generating units (EGUs). The proposed rule establishes numeric emission limits for acid gases, mercury, and total particulate matter. Meeting the proposed limits would likely require additional emission control equipment such as scrubbers, SCRs, baghouses, and other control measures at many coal-fired EGUs. Pursuant to a court-approved consent decree, the EPA must issue a final rule by November 16, 2011. Compliance for existing sources would be required three years after the effective date of the final rule. In the proposed rule, the EPA discussed the possibility of a one-year compliance extension which could be granted by the EPA or the states on a case-by-case basis if necessary. If finalized as proposed, compliance with this rule would require significant capital expenditures and compliance costs at many of Gulf Power's facilities which could impact unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be impacted if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the proposed rule within the proposed compliance period, and the limited compliance period could negatively impact electric system reliability. The outcome of this rulemaking cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Gulf Power in Item 7 of the Form 10-K for additional information regarding regulation of water quality. On April 20, 2011, the EPA proposed a rule that establishes standards for reducing impacts to fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. The rule focuses on reducing adverse impacts to fish and other aquatic life due to impingement (when fish and other aquatic life are trapped by water flow velocity against a facility's cooling water intake structure screens) and entrainment (when aquatic organisms are drawn through a facility's cooling water system after entering through the cooling water intake structure). Affected cooling water intake structures would have to comply with national impingement standards (for intake velocity or alternatively numeric impingement reduction standards) and entrainment reduction requirements (determined on a case-by-case basis). The rule's proposed impingement standards could require technological improvements to cooling water intake structures at many of Gulf Power's existing generating facilities, including facilities with closed-cycle re-circulating cooling systems (cooling towers). To address the rule's entrainment standards, facilities with once-through cooling systems may have to install cooling towers. New units constructed at existing plants would have to meet the national impingement standards and install closed-cycle cooling or the equivalent to meet the entrainment mandate. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of Gulf Power's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking cannot be determined at this time.

Florida PSC Matters

Fuel Cost Recovery

Gulf Power has established fuel cost recovery rates approved by the Florida PSC. In previous years, Gulf Power has experienced volatility in pricing of fuel commodities with higher than expected pricing for coal and volatile price swings in natural gas. If the projected fuel cost over or under recovery balance at year-end exceeds 10% of the projected fuel revenue applicable for the period, Gulf Power is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested.

Under recovered fuel costs at March 31, 2011 totaled $19.8 million, compared to $17.4 million at December 31, 2010. This amount is included in under recovered regulatory clause revenues on Gulf Power's Condensed Balance Sheets herein. Fuel cost recovery revenues, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, any change in the billing factor would have no significant effect on Gulf Power's revenues or net income, but would affect cash flow. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Gulf Power in Item 7 and Notes 1 and 3 to the financial statements of Gulf Power under "Revenues" and "Retail Regulatory Matters – Fuel Cost Recovery," respectively, in Item 8 of the Form 10-K for additional information.

Environmental Cost Recovery

In July 2010, Mississippi Power filed a request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $625 million and is scheduled for completion in early 2015. Hearings on the certificate request were held by the Mississippi PSC on January 25, 2011, but a final order has not yet been issued. On May 5, 2011, the Mississippi PSC approved up to $19.5 million (with respect to Mississippi Power's ownership portion) in spending for 2011 for the scrubber project. A decision on a final order is not anticipated prior to issuance of the final Utility MACT rule in November 2011. The ultimate outcome of this matter cannot be determined at this time. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Environmental Cost Recovery" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Environmental Cost Recovery" in Item 8 of the Form 10-K for additional information.

Energy Conservation Cost Recovery

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

The most recent goal setting process established new DSM goals for the period 2010-2019. The new goals are significantly larger than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. Throughout 2010, Gulf Power engaged in a process at the Florida PSC to develop plans and programs to meet the new DSM goals. The DSM program standards were approved in April 2011, which allow Gulf Power to implement its DSM programs designed to meet the new goals. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

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

Income Tax Matters

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects to be placed in service in 2011). Additionally, in December 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 will have a positive impact on the future cash flows of Gulf Power. On March 29, 2011, the IRS issued additional guidance and safe harbors relating to the 50% and 100% bonus depreciation rules. Based on this guidance, Gulf Power estimates the potential increased cash flow for 2011 to be between approximately $30 million and $40 million. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Gulf Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Gulf Power is subject to certain claims and legal actions arising in the ordinary course of business. Gulf Power'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 Gulf Power cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Gulf Power in Item 8 of the Form 10-K, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on Gulf Power's financial statements.

See the Notes to the Condensed Financial Statements herein for discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Gulf Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Gulf Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Gulf Power'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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Gulf Power in Item 7 of the Form 10-K for a complete discussion of Gulf Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, Unbilled Revenues, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Gulf Power's financial condition remained stable at March 31, 2011. Gulf Power 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.

Net cash provided from operating activities totaled $87.2 million for the first three months of 2011 compared to $100.6 million for the corresponding period in 2010. The $13.4 million decrease was primarily due to a $32.4 million use of cash related to fuel inventory increases in 2011 compared to reductions in 2010, a $13.6 million decrease in net income, and an $8.4 million decrease due to payments to non-affiliates, partially offset by a $27.9 million increase related to the declining balance of customer receivables in 2011 compared to its increasing balance in 2010, which was driven by weather-related demands, and a $13.7 million increase from taxes primarily related to refunds received. Net cash used for investing activities totaled $98.5 million in the first three months of 2011 compared to $97.4 million for the corresponding period in 2010. The $1.1 million increase in cash used was primarily due to gross property additions. Net cash provided from financing activities totaled $15.1 million for the first three months of 2011, compared to $17.4 million for the corresponding period in 2010. The $2.3 million decrease was primarily due to higher common stock dividends in 2011.

Significant balance sheet changes for the first quarter 2011 include a net increase of $76.5 million in property, plant, and equipment, primarily related to environmental control projects; the issuance of common stock to Southern Company for $50 million; a decrease of $32.5 million in prepaid expenses, primarily related to prepaid income taxes; and a $14.9 million increase in fossil fuel stock.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Gulf Power in Item 7 of the Form 10-K for a description of Gulf Power's capital requirements for its construction program, maturities of long-term debt, as well as the related interest, leases, derivative obligations, preference stock dividends, purchase commitments, and trust funding requirements. Approximately $110 million will be required through March 31, 2012 for maturities of long-term debt.

The construction program of Gulf Power 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, Gulf Power currently estimates that potential incremental investments to comply with anticipated new environmental regulations are up to $17.1 million for 2011, up to $55.6 million for 2012, and up to $107.3 million for 2013. If the EPA's proposed Utility MACT rule is finalized as proposed, Gulf Power estimates the potential investments in 2011 through 2013 for new environmental regulations will be closer to the upper end of the ranges set forth above. 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.

Sources of Capital

Gulf Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, a long-term bank note, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Gulf Power in Item 7 of the Form 10-K for additional information.

Gulf Power'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, Gulf Power had at March 31, 2011 approximately $20.2 million of cash and cash equivalents and $240 million of unused committed credit arrangements with banks that will expire in 2011. During the first quarter of 2011, one line of credit for $30 million was extended until July 2011. Subsequent to March 31, 2011, Gulf Power extended the maturity on two other lines of credit totaling $75 million until July 2011. Gulf Power expects to renew these lines of credit in July for at least a 364-day period. Of the credit arrangements, $210 million contain provisions allowing one-year term loans executable at expiration. Gulf Power expects to renew its credit arrangements, as needed, prior to expiration. These credit arrangements provide liquidity support to Gulf Power's commercial paper borrowings and $69 million are dedicated to funding purchase obligations related to variable rate pollution control revenue bonds. See Note 6 to the financial statements of Gulf Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information. Gulf Power 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 Gulf Power and other Southern Company subsidiaries. At March 31, 2011, Gulf Power had $83.0 million of commercial paper borrowings outstanding with a weighted average interest rate of 0.3% per annum. During the first quarter 2011, Gulf Power had an average of $55 million of commercial paper outstanding at a weighted average interest rate of 0.3 % per annum and the maximum amount outstanding was $103 million. Management believes that the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, and cash.

Credit Rating Risk

Gulf Power 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 March 31, 2011, the maximum potential collateral requirements under these contracts at a BBB- and/or Baa3 rating were approximately $125 million. At March 31, 2011, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $530 million. Included in these amounts are certain agreements that could require collateral in the event that one or more 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 Gulf Power's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Gulf Power's market risk exposure relative to interest rate changes for the first quarter 2011 has not changed materially compared with the December 31, 2010 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, Gulf Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Gulf Power continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to movements in electricity prices, Gulf Power 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. Gulf Power continues to manage a financial hedging program for fuel purchased to operate its electric generating fleet implemented per the guidelines of the Florida PSC. As such, Gulf Power had no material change in market risk exposure for the first quarter 2011 when compared with the December 31, 2010 reporting period.

The changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, for the three months ended March 31, 2011 were as follows:

	First Quarter 2011 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(11)
Contracts realized or settled	2
Current period changes(a)	1
Contracts outstanding at the end of the period, assets (liabilities), net	$ (8)

(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 three months ended March 31, 2011 was an increase of $3 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of mmBtu and prices of natural gas. At March 31, 2011, Gulf Power had a net hedge volume of 20.3 million mmBtu with a weighted average contract cost approximately $0.46 per mmBtu above market prices, compared to 19.6 million mmBtu at December 31, 2010 with a weighted average contract cost approximately $0.67 per mmBtu above market prices. Natural gas settlements are recovered through the fuel cost recovery clause.

Regulatory hedges relate to Gulf Power's fuel-hedging program where 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.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2011 and 2010 for energy-related derivative contracts that are not hedges were not material.

Gulf Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2011 were as follows:

	March 31, 2011 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ -	$ -	$ -	$-
Level 2	(8)	(5)	(3)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(8)	$(5)	$(3)	$-

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 Gulf Power. 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.

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Gulf Power in Item 7 and Note 1 under "Financial Instruments" and Note 10 to the financial statements of Gulf Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

On January 20, 2011, Gulf Power 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 Gulf Power's short-term indebtedness and for other general corporate purposes, including Gulf Power's continuous construction program.

Subsequent to March 31, 2011, Gulf Power extended the maturity date of a $110 million variable rate bank note until June 30, 2011.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm-recovery, Gulf Power 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.

[This page intentionally left blank]

MISSISSIPPI POWER COMPANY

MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2011	2010
	(in thousands)	
Operating Revenues:		
Retail revenues	**$ 180,474**	$ 186,587
Wholesale revenues, non-affiliates	**69,851**	78,889
Wholesale revenues, affiliates	**9,300**	14,675
Other revenues	**3,651**	3,487
Total operating revenues	**263,276**	283,638
Operating Expenses:		
Fuel	**121,054**	130,797
Purchased power, non-affiliates	**1,010**	3,621
Purchased power, affiliates	**8,350**	14,721
Other operations and maintenance	**70,367**	67,338
Depreciation and amortization	**19,863**	18,675
Taxes other than income taxes	**17,481**	18,460
Total operating expenses	**238,125**	253,612
Operating Income	**25,151**	30,026
Other Income and (Expense):		
Allowance for equity funds used during construction	**3,131**	18
Interest income	**342**	33
Interest expense, net of amounts capitalized	**(6,013)**	(6,179)
Other income (expense), net	**(403)**	1,531
Total other income and (expense)	**(2,943)**	(4,597)
Earnings Before Income Taxes	**22,208**	25,429
Income taxes	**7,158**	9,743
Net Income	**15,050**	15,686
Dividends on Preferred Stock	**433**	433
Net Income After Dividends on Preferred Stock	**$ 14,617**	$ 15,253

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2011	2010
	(in thousands)	
Net Income After Dividends on Preferred Stock	**$ 14,617**	$ 15,253
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $(1) and $12, respectively	**(2)**	20
Comprehensive Income	**$ 14,615**	$ 15,273

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Operating Activities:		
Net income	**$ 15,050**	$ 15,686
Adjustments to reconcile net income		
to net cash provided from operating activities --		
Depreciation and amortization, total	**21,442**	20,118
Deferred income taxes	**10,015**	(8,080)
Investment tax credits received	**9,750**	-
Allowance for equity funds used during construction	**(3,131)**	(18)
Pension, postretirement, and other employee benefits	**1,037**	1,822
Stock based compensation expense	**813**	757
Tax benefit of stock options	**73**	24
Generation construction screening costs	**-**	(18,832)
Other, net	**(1,436)**	1,138
Changes in certain current assets and liabilities --		
-Receivables	**11,592**	7,715
-Fossil fuel stock	**(538)**	17,761
-Materials and supplies	**(317)**	(885)
-Prepaid income taxes	**15,976**	-
-Other current assets	**1,649**	(8,262)
-Accounts payable	**17,538**	970
-Accrued taxes	**(31,213)**	(12,109)
-Accrued compensation	**(9,556)**	(7,719)
-Over recovered regulatory clause revenues	**7,756**	7,596
-Other current liabilities	**(149)**	(708)
Net cash provided from operating activities	**66,351**	16,974
Investing Activities:		
Property additions	**(148,917)**	(19,054)
Cost of removal, net of salvage	**(2,830)**	(3,375)
Construction payables	**33,291**	2,812
Capital grant proceeds	**16,912**	-
Distribution of restricted cash	**50,000**	-
Other investing activities	**(834)**	(5,316)
Net cash used for investing activities	**(52,378)**	(24,933)
Financing Activities:		
Proceeds --		
Capital contributions from parent company	**50,610**	752
Gross excess tax benefit of stock options	**106**	75
Redemptions --		
Capital leases	**(349)**	(323)
Other long-term debt	**(130,000)**	-
Payment of preferred stock dividends	**(433)**	(433)
Payment of common stock dividends	**(18,875)**	(17,150)
Other financing activities	**(418)**	(1)
Net cash used for financing activities	**(99,359)**	(17,080)
Net Change in Cash and Cash Equivalents	**(85,386)**	(25,039)
Cash and Cash Equivalents at Beginning of Period	**160,779**	65,025
Cash and Cash Equivalents at End of Period	**$ 75,393**	$ 39,986
Supplemental Cash Flow Information:		
Cash paid during the period for --		
Interest (net of $994 and $9 capitalized for 2011 and 2010, respectively)	**$6,135**	$7,028
Income taxes (net of refunds)	**(32,294)**	(3,821)
Noncash transactions - accrued property additions at end of period	**72,114**	6,501

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	**At March 31, 2011**	At December 31, 2010
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 75,393**	$ 160,779
Restricted cash and cash equivalents	**-**	50,000
Receivables --		
Customer accounts receivable	**31,355**	37,532
Unbilled revenues	**25,992**	31,010
Other accounts and notes receivable	**9,345**	11,220
Affiliated companies	**30,905**	17,837
Accumulated provision for uncollectible accounts	**(467)**	(638)
Fossil fuel stock, at average cost	**112,777**	112,240
Materials and supplies, at average cost	**28,988**	28,671
Other regulatory assets, current	**60,440**	63,896
Prepaid income taxes	**46,458**	59,596
Other current assets	**21,482**	19,057
Total current assets	**442,668**	591,200
Property, Plant, and Equipment:		
In service	**2,416,242**	2,392,477
Less accumulated provision for depreciation	**980,896**	971,559
Plant in service, net of depreciation	**1,435,346**	1,420,918
Construction work in progress	**383,619**	274,585
Total property, plant, and equipment	**1,818,965**	1,695,503
Other Property and Investments	**6,111**	5,900
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**21,521**	18,065
Other regulatory assets, deferred	**128,379**	132,420
Other deferred charges and assets	**20,357**	33,233
Total deferred charges and other assets	**170,257**	183,718
Total Assets	**$ 2,438,001**	$ 2,476,321

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At March 31, 2011**	At December 31, 2010
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 126,465**	$ 256,437
Accounts payable --		
Affiliated	**48,146**	51,887
Other	**116,911**	59,295
Customer deposits	**13,181**	12,543
Accrued taxes --		
Accrued income taxes	**8,753**	4,356
Other accrued taxes	**16,147**	51,709
Accrued interest	**5,132**	5,933
Accrued compensation	**6,521**	16,076
Other regulatory liabilities, current	**5,730**	6,177
Over recovered regulatory clause liabilities	**84,802**	77,046
Liabilities from risk management activities	**24,825**	27,525
Other current liabilities	**20,454**	20,115
Total current liabilities	**477,067**	589,099
Long-term Debt	**461,696**	462,032
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**298,724**	281,967
Deferred credits related to income taxes	**12,096**	11,792
Accumulated deferred investment tax credits	**43,098**	33,678
Employee benefit obligations	**114,369**	113,964
Other cost of removal obligations	**115,192**	111,614
Other regulatory liabilities, deferred	**60,452**	58,814
Other deferred credits and liabilities	**37,865**	43,213
Total deferred credits and other liabilities	**681,796**	655,042
Total Liabilities	**1,620,559**	1,706,173
Redeemable Preferred Stock	**32,780**	32,780
Common Stockholder's Equity:		
Common stock, without par value --		
Authorized - 1,130,000 shares		
Outstanding - 1,121,000 shares	**37,691**	37,691
Paid-in capital	**444,344**	392,790
Retained earnings	**302,627**	306,885
Accumulated other comprehensive income (loss)	**-**	2
Total common stockholder's equity	**784,662**	737,368
Total Liabilities and Stockholder's Equity	**$ 2,438,001**	$ 2,476,321

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

FIRST QUARTER 2011 vs. FIRST QUARTER 2010

OVERVIEW

Mississippi Power operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Mississippi and to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of Mississippi Power'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, capital expenditures, and restoration following major storms. Mississippi Power has various regulatory mechanisms that operate to address cost recovery. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Mississippi Power for the foreseeable future.

Mississippi Power continues to focus on several key performance indicators. In recognition that Mississippi Power's long-term financial success is dependent upon how well it satisfies its customers' needs, Mississippi Power's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to Mississippi Power's allowed return. In addition to the PEP performance indicators, Mississippi Power focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Mississippi Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(0.7)	(4.2)

Mississippi Power's net income after dividends on preferred stock for the first quarter 2011 was $14.6 million compared to $15.3 million for the corresponding period in 2010. The decrease in net income after dividends on preferred stock for the first quarter 2011 was primarily due to an increase in other operations and maintenance expenses, a decrease in other income (expense), net primarily resulting from a decrease in amounts collected from customers for contributions in aid of construction, a decrease in capacity revenues from customers served outside Mississippi Power's service territory, and a decrease in territorial base revenues due to significantly colder weather in the first quarter 2010. The decrease in net income after dividends on preferred stock for the first quarter 2011 was partially offset by an increase in AFUDC equity resulting from construction of the Kemper IGCC.

Retail Revenues

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(6.1)	(3.3)

In the first quarter 2011, retail revenues were $180.5 million compared to $186.6 million for the corresponding period in 2010.

Details of the change to retail revenues are as follows:

	First Quarter 2011	
	(in millions)	*(% change)*
Retail – prior year	$186.6	
Estimated change in –		
Rates and pricing	1.0	0.5
Sales growth (decline)	3.5	1.9
Weather	(4.0)	(2.2)
Fuel and other cost recovery	(6.6)	(3.5)
Retail – current year	$180.5	(3.3)%

Revenues associated with changes in rates and pricing increased in the first quarter 2011 when compared to the corresponding period in 2010 due to an increase of $1.0 million related to the ECO Plan rate. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Environmental Compliance Overview Plan" of Mississippi Power in Item 7 of the Form 10-K and FUTURE EARNINGS POTENTIAL – "Mississippi PSC Matters – Retail Regulatory Matters – Environmental Compliance Overview Plan" herein for additional information.

Revenues attributable to changes in sales increased in the first quarter 2011 when compared to the corresponding period in 2010, primarily resulting from the continued recovery of some larger industrial customers. KWH energy sales to industrial customers increased 6.5% due to increased production for several large industrial customers resulting from improving economic conditions. Weather-adjusted KWH energy sales to the residential and commercial customers remained relatively flat when compared to the corresponding period in 2010.

Revenues attributable to changes in weather decreased in the first quarter 2011 when compared to the corresponding period for 2010 primarily due to significantly colder weather in the first quarter 2010.

Fuel and other cost recovery revenues decreased in the first quarter 2011 when compared to the corresponding period in 2010 primarily as a result of lower recoverable fuel costs. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel portion of wholesale revenues from energy sold to customers outside Mississippi Power's service territory. Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power costs, and do not affect net income.

Wholesale Revenues – Non-Affiliates

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(9.0)	(11.5)

Wholesale revenues from non-affiliates will vary depending on fuel prices, the market cost of available energy compared to the cost of Mississippi Power and Southern Company system-owned generation, demand for energy within the Southern Company service territory, and the availability of Southern Company system generation. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

In the first quarter 2011, wholesale revenues from non-affiliates were $69.9 million compared to $78.9 million for the corresponding period in 2010. The decrease was due to $6.6 million in decreased revenues from customers inside Mississippi Power's service territory and $2.4 million in decreased revenues from customers outside Mississippi Power's service territory. The $6.6 million decrease in revenues from customers inside Mississippi Power's service territory was primarily due to a $6.1 million decrease in fuel revenues and a $0.5 million decrease in wholesale base revenues due to significantly colder weather in the first quarter 2010, partially offset by a wholesale base rate increase effective January 2011. The $2.4 million decrease in revenues from customers outside Mississippi Power's service territory was primarily due to a $1.1 million decrease in sales, a $0.5 million decrease associated with lower prices resulting from lower marginal cost of fuel, and a $0.8 million decrease in capacity revenues.

Wholesale Revenues – Affiliates

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(5.4)	(36.6)

Wholesale revenues from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost.

In the first quarter 2011, wholesale revenues from affiliates were $9.3 million compared to $14.7 million for the corresponding period in 2010. The decrease was primarily due to a $4.4 million decrease in energy revenues, of which $2.9 million was associated with decreased sales and $1.5 million was associated with lower prices. Capacity revenues decreased by $1.0 million.

Fuel and Purchased Power Expenses

First Quarter 2011 vs. First Quarter 2010		
	(change in millions)	*(% change)*
Fuel	$ (9.7)	(7.4)
Purchased power – non-affiliates	(2.6)	(72.1)
Purchased power – affiliates	(6.4)	(43.3)
Total fuel and purchased power expenses	$ (18.7)	

In the first quarter 2011, total fuel and purchased power expenses were $130.4 million compared to $149.1 million for the corresponding period in 2010. The decrease was primarily due to an $11.7 million decrease in cost of fuel and purchased power and a $7.0 million decrease in total KWHs generated and purchased.

Fuel and purchased power transactions do not have a significant impact on earnings since energy expenses are generally offset by energy revenues through Mississippi Power's fuel cost recovery clause. See FUTURE EARNINGS POTENTIAL – "Mississippi PSC Matters – Retail Regulatory Matters" herein for additional information.

Details of Mississippi Power's cost of generation and purchased power are as follows:

Average Cost	First Quarter 2011	First Quarter 2010	Percent Change
	(cents per net KWH)		
Fuel	3.92	4.23	(7.3)
Purchased power	3.08	3.76	(18.1)

In the first quarter 2011, fuel expense was $121.1 million compared to $130.8 million for the corresponding period in 2010. The decrease was primarily due to a 7.3% decrease in the price of fuel primarily resulting from lower gas prices and a 0.1% decrease in generation from Mississippi Power facilities resulting from lower energy demand in the first quarter 2011 compared to the corresponding period in 2010.

Non-Affiliates

In the first quarter 2011, purchased power expense from non-affiliates was $1.0 million compared to $3.6 million for the corresponding period in 2010. The decrease was primarily the result of a 54.2% decrease in the average cost of purchased power per KWH and a 39.1% decrease in KWH volume purchased. The decrease in prices was due to a lower marginal cost of fuel while the decrease in volume was a result of higher cost opportunity purchases.

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

Affiliates

In the first quarter 2011, purchased power expense from affiliates was $8.3 million compared to $14.7 million for the corresponding period in 2010. The decrease was primarily due to a 37.3% decrease in KWH volume purchased and a 9.5% decrease in the average cost of purchased power per KWH.

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

Other Operations and Maintenance Expenses

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$3.1	4.5

In the first quarter 2011, other operations and maintenance expenses were $70.4 million compared to $67.3 million for the corresponding period in 2010. The increase was primarily due to a $2.9 million increase in generation maintenance expenses for several major scheduled outages and a $1.0 million increase in expense for a combined cycle long-term service agreement due to a 29% increase in operating hours as a result of lower gas prices. These expenses were partially offset by a $0.7 million decrease in administrative and general expenses primarily due to pension costs and other employee benefits.

Depreciation and Amortization

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$1.2	6.4

In the first quarter 2011, depreciation and amortization was $19.9 million compared to $18.7 million for the corresponding period in 2010. The increase was primarily due to a $1.0 million increase in depreciation resulting from an increase in plant in service.

Taxes Other Than Income Taxes

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(1.0)	(5.3)

In the first quarter 2011, taxes other than income taxes were $17.5 million compared to $18.5 million for the corresponding period in 2010. The decrease was primarily due to a $1.3 million decrease in ad valorem taxes and a $0.2 million decrease in franchise taxes, partially offset by a $0.4 million increase in corporate franchise taxes and a $0.1 million increase in payroll taxes.

The retail portion of ad valorem taxes is recoverable under Mississippi Power's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Allowance for Equity Funds Used During Construction

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$3.1	N/M

N/M – Not meaningful

In the first quarter 2011, AFUDC equity increased $3.1 million as compared to the corresponding period in 2010 primarily due to increases in construction of the Kemper IGCC which began in June 2010 with the approval of the certificate order by the Mississippi PSC. See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(0.2)	(2.7)

In the first quarter 2011, interest expense, net of amounts capitalized was $6.0 million compared to $6.2 million for the corresponding period in 2010. The decrease was primarily due to a $1.0 million increase in AFUDC debt expense primarily associated with the Kemper IGCC, partially offset by a $0.7 million increase in interest expense associated with the issuance of new long-term debt in September and December 2010.

Other Income (Expense), Net

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
($1.9)	N/M

N/M – Not meaningful

In the first quarter 2011, other income (expense), net was ($0.4) million compared to $1.5 million for the corresponding period in 2010. The decrease was primarily due to a $1.5 million decrease in amounts collected from customers for contributions in aid of construction and a $0.5 million decrease in customer projects.

Income Taxes

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(2.5)	(26.5)

In the first quarter 2011, income taxes were $7.2 million compared to $9.7 million for the corresponding period in 2010. The decrease was primarily due to a $1.3 million decrease resulting from the decrease in pre-tax earnings and a $1.2 million decrease due to an increase in AFUDC equity which is non-taxable.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Mississippi Power's future earnings potential. The level of Mississippi Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Mississippi Power's business of selling electricity. These factors include Mississippi Power'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 Mississippi Power's service area. Changes in economic conditions impact sales for Mississippi Power 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. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Mississippi Power in Item 7 of the Form 10-K.

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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

New Source Review Actions

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – New Source Review Actions" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Environmental Matters – New Source Review Actions" in Item 8 of the Form 10-K for additional information regarding civil actions brought by the EPA against certain Southern Company subsidiaries. The EPA's action against Alabama Power alleged that Alabama Power violated the NSR provisions of the Clean Air Act and related state laws with respect to certain of its coal-fired generating facilities. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power's motion for summary judgment on all remaining claims and dismissed the case with prejudice. The EPA has the right to appeal within 60 days of the order. The ultimate outcome of this matter cannot be determined at this time.

Carbon Dioxide Litigation

Kivalina Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" in Item 8 of the Form 10-K for additional information regarding carbon dioxide litigation. On February 23, 2011, the U.S. Court of Appeals for the Ninth Circuit issued an order staying the case until June 15, 2011. The ultimate outcome of this matter cannot be determined at this time.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Mississippi Power in Item 7 of the Form 10-K for additional information regarding regulation of air quality. On May 3, 2011, the EPA published a proposed rule, called Utility MACT (Maximum Achievable Control Technology), which would impose stringent emission limits on coal- and oil-fired electric utility steam generating units (EGUs). The proposed rule establishes numeric emission limits for acid gases, mercury, and total particulate matter. Meeting the proposed limits would likely require additional emission control equipment such as scrubbers, SCRs, baghouses, and other control measures at many coal-fired EGUs. Pursuant to a court-approved consent decree, the EPA must issue a final rule by November 16, 2011. Compliance for existing sources would be required three years after the effective date of the final rule. In the proposed rule, the EPA discussed the possibility of a one-year compliance extension which could be granted by the EPA or the states on a case-by-case basis if necessary. If finalized as proposed, compliance with this rule would require significant capital expenditures and compliance costs at many of Mississippi Power's facilities which could impact unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be impacted if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the proposed rule within the proposed compliance period, and the limited compliance period could negatively impact electric system reliability. The outcome of this rulemaking cannot be determined at this time.

In October 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity which granted some flexibility to affected sources while requiring compliance with Alabama's very strict opacity limits through use of continuous opacity monitoring system data. In a decision published on April 6, 2011, the EPA responded to an environmental group's request for reconsideration by attempting to rescind its previous approval of the Alabama SIP revision. Mississippi Power's jointly-owned facility with Alabama Power in Greene County, Alabama is impacted by this decision. On April 8, 2011, Alabama Power filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit and requested the court to stay the effectiveness of the EPA's attempted rescission pending judicial review. Absent a stay, the EPA's decision will become effective May 6, 2011 and the rule under which Alabama Power has been operating since January 2009 may not be available unless Alabama Power's appeal is resolved in its favor by the court. If the EPA's decision is allowed to take effect, it will likely impact unit availability and result in increased maintenance and compliance costs. The final outcome of this matter cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Mississippi Power in Item 7 of the Form 10-K for additional information regarding regulation of water quality. On April 20, 2011, the EPA proposed a rule that establishes standards for reducing impacts to fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. The rule focuses on reducing adverse impacts to fish and other aquatic life due to impingement (when fish and other aquatic life are trapped by water flow velocity against a facility's cooling water intake structure screens) and entrainment (when aquatic organisms are drawn through a facility's cooling water system after entering through the cooling water intake structure). Affected cooling water intake structures would have to comply with national impingement standards (for intake velocity or alternatively numeric impingement reduction standards) and entrainment reduction requirements (determined on a case-by-case basis). The rule's proposed impingement standards could require technological improvements to cooling water intake structures at many of Mississippi Power's existing generating facilities, including facilities with closed-cycle re-circulating cooling systems (cooling towers). To address the rule's entrainment standards, facilities with once-through cooling systems may have to install cooling towers. New units constructed at existing plants would have to meet the national impingement standards and install closed-cycle cooling or the equivalent to meet the entrainment mandate. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of Mississippi Power's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking cannot be determined at this time.

Mississippi PSC Matters

Retail Regulatory Matters

Performance Evaluation Plan

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Performance Evaluation Plan" in Item 8 of the Form 10-K for additional information regarding Mississippi Power's base rates.

In November 2010, Mississippi Power filed its annual PEP filing for 2011, which indicated a rate increase of 1.936%, or $16.1 million, annually. On January 10, 2011, the Mississippi Public Utilities Staff (MPUS) contested the filing. The ultimate outcome of this matter cannot be determined at this time.

On March 15, 2011, Mississippi Power submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. On May 2, 2011, Mississippi Power received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. The ultimate outcome of this matter cannot be determined at this time.

System Restoration Rider

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – System Restoration Rider" of Mississippi Power in Item 7 of the Form 10-K for additional information.

On January 31, 2011, Mississippi Power submitted its 2011 SRR rate filing with the Mississippi PSC, which proposed that Mississippi Power be allowed to accrue approximately $3.6 million to the property damage reserve in 2011. On May 5, 2011, the filing was approved by the Mississippi PSC.

Environmental Compliance Overview Plan

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Environmental Compliance Overview Plan" in Item 8 of the Form 10-K for information on Mississippi Power's annual environmental filing with the Mississippi PSC.

On February 14, 2011, Mississippi Power submitted its ECO Plan notice which proposed an immaterial decrease in annual revenues. In addition, Mississippi Power proposed to change the ECO Plan collection period to more appropriately match ECO revenues with ECO expenditures. On April 7, 2011, due to changes in ECO Plan cost projections, Mississippi Power submitted a revised 2011 ECO Plan which changed the requested annual revenues to a \$0.9 million decrease. On May 5, 2011, hearings on the revised ECO Plan were held and the filing was approved by the Mississippi PSC with the new rates effective in May 2011.

In July 2010, Mississippi Power filed a request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately \$625 million with Mississippi Power's portion being \$312.5 million. As of March 31, 2011, total project expenditures were \$19.5 million with Mississippi Power's portion being \$9.7 million. The project is scheduled for completion in early 2015. Mississippi Power's portion of the cost, if approved by the Mississippi PSC, is expected to be recovered through the ECO Plan. Hearings on the certificate request were held by the Mississippi PSC on January 25, 2011, but a final order has not yet been issued. On May 5, 2011, in conjunction with the ECO Plan hearings, the Mississippi PSC approved up to \$19.5 million (with respect to Mississippi Power's ownership portion) in spending for 2011 for the scrubber project. A decision on a final order is not anticipated prior to issuance of the final Utility MACT rule in November 2011. The ultimate outcome of this matter cannot be determined at this time.

Certificated New Plant

On April 27, 2011, Mississippi Power submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-A (CNP-A), a new proposed cost recovery mechanism designed specifically to recover financing costs during the construction phase of the Kemper IGCC. Annual CNP-A rate filings would be made with the first filing occurring in November 2011. If approved by the Mississippi PSC, recovery through CNP-A will remain in place thereafter until the end of the calendar year that the Kemper IGCC is placed into commercial service, which is projected to be 2014. Certificated New Plant-B, which will be filed at a later date, would propose to govern rates effective from the first calendar year after the Kemper IGCC is placed into commercial service through the first seven full calendar years of its operation. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Mississippi Power in Item 7 of the Form 10-K for information regarding Mississippi Power's fuel cost recovery. Mississippi Power establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. Mississippi Power is required to file for an adjustment to the retail fuel cost recovery factor annually; such filing occurred in November 2010. The Mississippi PSC approved the retail fuel cost recovery factor in December 2010, with the new rates effective in January 2011. The retail fuel cost recovery factor will result in an annual decrease in an amount equal to 5.0% of total 2010 retail revenue. At March 31, 2011, the amount of over recovered retail fuel costs included in the balance sheets was \$57.7 million compared to \$55.2 million at December 31, 2010. Mississippi Power also has a wholesale Municipal and Rural Associations (MRA) and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2011, the wholesale MRA fuel rate decreased, resulting in an annual decrease in an amount equal to 3.5% of total 2010 MRA revenue. Effective February 1, 2011, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 7.0% of total 2010 MB revenue. At March 31, 2011, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was \$21.6 million and \$5.2 million compared to \$17.5 million and \$4.4 million, respectively, at December 31, 2010. In addition, at March 31, 2011, the amount of over recovered MRA emissions allowance cost included in the balance sheet was \$0.4 million. See Note 3 to the financial statements of Mississippi Power under "FERC Matters" in Item 8 of the Form 10-K for additional information. Mississippi Power's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, this decrease to the billing factors will have no significant effect on Mississippi Power's revenues or net income, but will decrease annual cash flow.

In October 2010, the Mississippi PSC engaged an independent professional audit firm to conduct an audit of Mississippi Power's fuel-related expenditures included in the retail fuel adjustment clause and energy cost management clause (ECM) for 2010. The audit was completed in the first quarter 2011 with no audit findings.

Integrated Coal Gasification Combined Cycle

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and "PSC Matters – Mississippi Baseload Construction Legislation" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K for information regarding the Kemper IGCC.

In June 2010, the Mississippi Chapter of the Sierra Club (Sierra Club) filed an appeal of the Mississippi PSC's June 3, 2010 decision to grant the Certificate of Public Convenience and Necessity for the Kemper IGCC with the Chancery Court of Harrison County, Mississippi (Chancery Court). Subsequently, in July 2010, the Sierra Club also filed an appeal directly with the Mississippi Supreme Court. In October 2010, the Mississippi Supreme Court dismissed the Sierra Club's direct appeal. On February 28, 2011, the Chancery Court issued a judgment affirming the Mississippi PSC's order authorizing the construction of the Kemper IGCC. On March 1, 2011, the Sierra Club appealed the Chancery Court's decision to the Mississippi Supreme Court.

In May 2009, Mississippi Power received notification from the IRS formally certifying the IRS allocated Internal Revenue Code Section 48A tax credits (Phase I) of $133 million to Mississippi Power. On April 19, 2011, Mississippi Power received notification from the IRS formally certifying that the IRS allocated $279 million of Internal Revenue Code Section 48A tax credits (Phase II) to Mississippi Power. The utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II tax credits, Mississippi Power plans to capture and sequester (via enhanced oil recovery) at least 65% of the carbon dioxide (CO_2) produced by the plant during operations in accordance with the recapture rules for Section 48A investment tax credits. Through March 31, 2011, Mississippi Power received and accrued tax benefits totaling $31.9 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC.

In February 2008, Mississippi Power requested that the DOE transfer the remaining funds previously granted under the Clean Coal Power Initiative Round 2 (CCPI2) from a cancelled IGCC project of one of Southern Company's subsidiaries that would have been located in Orlando, Florida. In December 2008, an agreement was reached to assign the remaining funds ($270 million) to the Kemper IGCC. Mississippi Power will receive grant funds of $245 million during the construction of the plant and $25 million during the initial operation of the plant. Through March 31, 2011, Mississippi Power has received $40 million and requested an additional $20.1 million associated with this grant.

On March 10, 2011, the Sierra Club filed a lawsuit in the U.S. District Court for the District of Columbia against the DOE regarding the National Environmental Policy Act review process asking for a stay on the issuance of CCPI2 funds and a stay to any related construction activities. On May 5, 2011, Mississippi Power filed a motion to intervene in this lawsuit.

In March 2010, the Mississippi Department of Environmental Quality (MDEQ) issued the Prevention of Significant Deterioration (PSD) air permit modification for the plant, which modifies the original PSD air permit issued in October 2008. The Sierra Club requested a formal evidentiary hearing regarding the issuance of the modified permit. On April 4, 2011, the MDEQ Permit Board held an evidentiary hearing wherein the permit board unanimously affirmed the PSD air permit.

On March 4, 2011, Mississippi Power and Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., entered into a contract in which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC.

On April 27, 2011, Mississippi Power submitted to the Mississippi PSC a proposed rate schedule detailing CNP-A, a new proposed cost recovery mechanism designed specifically to recover financing costs during the construction phase of the Kemper IGCC. See "Mississippi PSC Matters – Retail Regulatory Matters – Certificated New Plant" herein for additional information.

Events in Japan resulting from the earthquake and tsunami created uncertainties that may affect transportation and availability of equipment or supplies from Japanese manufacturers in connection with the construction of the Kemper IGCC.

As of March 31, 2011, Mississippi Power had spent a total of $352.8 million on the Kemper IGCC, including regulatory filing costs. Of this total, $277 million was included in CWIP (net of $60.1 million of CCPI2 grant funds), $13.2 million was recorded in other regulatory assets, $1.5 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed.

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

Income Tax Matters

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects to be placed in service in 2011). Additionally, in December 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 will have a positive impact on the future cash flows of Mississippi Power. On March 29, 2011, the IRS issued additional guidance and safe harbors relating to the 50% and 100% bonus depreciation rules. Based on this guidance, Mississippi Power estimates the potential increased cash flow for 2011 to be between approximately $15 million and $20 million. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Mississippi Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Mississippi Power is subject to certain claims and legal actions arising in the ordinary course of business. Mississippi Power'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 Mississippi Power cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Mississippi Power in Item 8 of the Form 10-K, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on Mississippi Power's financial statements.

See the Notes to the Condensed Financial Statements herein for discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Mississippi Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Mississippi Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Mississippi Power'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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Mississippi Power in Item 7 of the Form 10-K for a complete discussion of Mississippi Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, Unbilled Revenues, Plant Daniel Operating Lease, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Mississippi Power's financial condition remained stable at March 31, 2011. Mississippi Power 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.

Net cash provided from operating activities totaled $66.4 million for the first three months of 2011 compared to $17.0 million for the corresponding period in 2010. The $49.4 million increase in cash provided from operating activities is primarily due to an $18.1 million increase in deferred income taxes primarily related to bonus depreciation, an increase in accounts payable of $16.6 million primarily due to timing of cash payments, an increase in investment tax credits of $9.7 million related to the Kemper IGCC, and an increase in cash of $18.8 million related to the Kemper IGCC generation construction screening costs incurred during the first quarter 2010. The Mississippi PSC issued an order in June 2010 approving the Kemper IGCC. These increases in cash are partially offset by a decrease of $18.3 million in fossil fuel stock resulting from an increase in Mississippi Power generation and a decrease in cash payments related to fuel inventory in the first quarter 2010.

Net cash used for investing activities totaled $52.4 million for the first three months of 2011 compared to $24.9 million for the corresponding period in 2010. The $27.4 million increase in net cash used for investing activities is primarily due to an increase in property additions of $129.9 million primarily related to the Kemper IGCC, partially offset by a $50.0 million decrease in restricted cash, a construction payables increase of $30.5 million, and the receipt of $16.9 million capital grant proceeds related to CCPI2.

Net cash used for financing activities totaled $99.4 million for the first three months of 2011, compared to net cash provided from financing activities of $17.1 million for the corresponding period in 2010. The $82.3 million increase in net cash used for financing activities was primarily due to the redemption of $50.0 million in revenue bonds and an $80.0 million maturity of long-term debt, partially offset by a $49.9 million increase in capital contributions from Southern Company.

Significant balance sheet changes for the first three months of 2011 include a decrease in cash and cash equivalents of $85.4 million primarily due to an $80.0 million long-term debt maturity and increased capital spending. Restricted cash and cash equivalents decreased $50.0 million due to the redemption of revenue bonds in February 2011. Total property, plant, and equipment increased $123.5 million primarily due to the increase in construction work in progress (CWIP) related to the Kemper IGCC. Other deferred charges and assets decreased $12.9 million primarily due to the reclassification of the Plant Daniel scrubber project and materials and supplies to CWIP. Securities due within one year decreased $130.0 million primarily due to a long-term bank loan of $80.0 million that matured in March 2011 and the redemption of revenue bonds of $50.0 million in February 2011. Other accounts payable increased $57.6 million primarily due to increases in construction projects. Other accrued taxes decreased $35.6 million primarily due to property tax payments of $44.1 million in the first quarter 2011. Paid-in capital increased $51.6 million primarily due to the $50.0 million capital contribution from Southern Company.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Mississippi Power in Item 7 of the Form 10-K for a description of Mississippi Power's capital requirements for its construction program, lease obligations, purchase commitments, derivative obligations, preferred stock dividends, and trust funding requirements. Approximately $126.5 million will be required through March 31, 2012 for maturities of long-term debt.

The construction program of Mississippi Power is currently estimated to include a base level investment of $818 million, $1.0 billion, and $878 million for 2011, 2012, and 2013, respectively. Included in these estimated amounts are expenditures related to the Kemper IGCC of $685 million, $813 million, and $616 million in 2011, 2012, and 2013, respectively. Also included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $20 million, $93 million, and $127 million for 2011, 2012, and 2013, respectively. In addition, Mississippi Power currently estimates that potential incremental investments to comply with anticipated new environmental regulations are $0 for 2011, up to $18 million for 2012, and up to $55 million for 2013. If the EPA's proposed Utility MACT rule is finalized as proposed, Mississippi Power estimates that the potential incremental investments in 2012 and 2013 for new environmental regulations will be closer to the upper end of the estimates set forth above. 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 retirement and replacement decisions, to meet new regulatory requirements; changes in FERC rules and regulations; Mississippi 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.

Sources of Capital

Except as described below with respect to potential DOE loan guarantees, Mississippi Power plans to obtain the funds required for construction and other purposes from sources similar to those utilized in the past. Mississippi Power has primarily utilized funds from operating cash flows, short-term borrowings, external security offerings, and capital contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. In March 2011, Mississippi Power received a $50 million capital contribution from Southern Company. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Mississippi Power in Item 7 of the Form 10-K for additional information.

Mississippi Power has applied to the DOE for federal loan guarantees to finance a portion of the eligible construction costs of the Kemper IGCC. Mississippi Power is in advanced due diligence with the DOE. There can be no assurance that the DOE will issue federal loan guarantees to Mississippi Power. In addition, Mississippi Power has been awarded DOE CCPI2 grant funds of $245 million to be used for the construction of the Kemper IGCC and $25 million to be used for the initial operation of the Kemper IGCC. As of March 31, 2011, Mississippi Power had received $40.0 million and requested an additional $20.1 million associated with this grant.

Mississippi Power's current liabilities sometimes 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, Mississippi Power had at March 31, 2011 approximately $75.4 million of cash and cash equivalents and $186 million of unused committed credit arrangements with banks. Of the unused credit arrangements, $161 million expire in 2011 and $25 million expire in 2012. Of these credit arrangements, $41 million contain provisions allowing for two-year term loans executable at expiration and $90 million contain provisions allowing for one-year term loans executable at expiration. Mississippi Power expects to renew its credit arrangements, as needed, prior to expiration. The credit arrangements provide liquidity support to Mississippi Power's commercial paper program and $40 million are dedicated to funding purchase obligations related to variable rate pollution control revenue bonds. See Note 6 to the financial statements of Mississippi Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information. Mississippi Power 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 Mississippi Power and other Southern Company subsidiaries. During the three months ended March 31, 2011, Mississippi Power had no commercial paper borrowings outstanding. Management believes that the need for working capital can be adequately met by utilizing commercial paper, lines of credit, and cash.

Off-Balance Sheet Financing Arrangements

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Off-Balance Sheet Financing Arrangements" of Mississippi Power in Item 7 and Note 7 to the financial statements of Mississippi Power under "Operating Leases" in Item 8 of the Form 10-K for information related to Mississippi Power's lease of a combined cycle generating facility at Plant Daniel. In April 2010, Mississippi Power was required to notify the lessor, Juniper Capital L.P., if it intended to terminate the lease at the end of the initial term expiring in October 2011. Mississippi Power chose not to give notice to terminate the lease. Mississippi Power has the option to purchase the units or renew the lease. Mississippi Power is required to provide notice of its intent to either renew the lease or purchase the facility by July 2011. The ultimate outcome of this matter cannot be determined at this time.

Credit Rating Risk

Mississippi Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are for physical electricity sales, fuel purchases, fuel transportation and storage, emissions allowances, and energy price risk management. At March 31, 2011, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $335 million. Included in these amounts are certain agreements that could require collateral in the event that one or more 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 Mississippi Power's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Mississippi Power's market risk exposure relative to interest rate changes for the first quarter 2011 has not changed materially compared with the December 31, 2010 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, Mississippi Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Mississippi Power continues to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity.

To mitigate residual risks relative to movements in electricity prices, Mississippi Power enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. Mississippi Power continues to manage retail fuel-hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel-hedging programs under agreements with wholesale customers. As such, Mississippi Power had no material change in market risk exposure for the first quarter 2011 when compared with the December 31, 2010 reporting period.

The changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, for the three months ended March 31, 2011 were as follows:

	First Quarter 2011 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(44)
Contracts realized or settled	7
Current period changes[(a)]	-
Contracts outstanding at the end of the period, assets (liabilities), net	$(37)

(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 three months ended March 31, 2011 was an increase of $7 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of mmBtu and the price of natural gas. At March 31, 2011, Mississippi Power had a net hedge volume of 24.3 million mmBtu with a weighted average contract cost approximately $1.79 per mmBtu above market prices, compared to 24.0 million mmBtu at December 31, 2010 with a weighted average contract cost approximately $1.92 per mmBtu above market prices. The majority of the natural gas hedges are recovered through the ECM.

Regulatory hedges relate to Mississippi Power's fuel-hedging program where 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 ECM.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2011 and 2010 for energy-related derivative contracts that are not hedges were not material.

Mississippi Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2011 were as follows:

	March 31, 2011 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ -	$ -	$ -	$-
Level 2	(37)	(24)	(13)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(37)	$(24)	$(13)	$-

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 Mississippi Power. 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.

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Mississippi Power in Item 7 and Note 1 under "Financial Instruments" and Note 10 to the financial statements of Mississippi Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

On February 8, 2011, Mississippi Power redeemed a $50 million series of revenue bonds issued in December 2010.

On March 4, 2011, an $80 million long term bank note with a variable interest rate based on one-month LIBOR matured.

In addition, subsequent to March 31, 2011, Mississippi Power entered into a one-year $75 million aggregate principal amount long-term floating rate bank loan with a variable interest rate based on one-month LIBOR. The proceeds of this loan were used to repay maturing long-term and short-term indebtedness and for other general corporate purposes, including Mississippi Power's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm restoration costs, Mississippi Power 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.

[This page intentionally left blank]

SOUTHERN POWER COMPANY
AND SUBSIDIARY COMPANIES

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2011	2010
	(in thousands)	
Operating Revenues:		
Wholesale revenues, non-affiliates	**$ 197,166**	$ 153,337
Wholesale revenues, affiliates	**83,274**	101,757
Other revenues	**1,347**	1,394
Total operating revenues	**281,787**	256,488
Operating Expenses:		
Fuel	**102,715**	97,514
Purchased power, non-affiliates	**8,942**	18,542
Purchased power, affiliates	**15,099**	23,411
Other operations and maintenance	**42,754**	39,010
Depreciation and amortization	**30,167**	29,109
Taxes other than income taxes	**4,763**	5,106
Total operating expenses	**204,440**	212,692
Operating Income	**77,347**	43,796
Other Income and (Expense):		
Interest expense, net of amounts capitalized	**(18,829)**	(20,054)
Other income (expense), net	**59**	418
Total other income and (expense)	**(18,770)**	(19,636)
Earnings Before Income Taxes	**58,577**	24,160
Income taxes	**20,834**	9,436
Net Income	**$ 37,743**	$ 14,724

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2011	2010
	(in thousands)	
Net Income	**$ 37,743**	$ 14,724
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $423 and $1,714, respectively	**643**	2,677
Reclassification adjustment for amounts included in net income, net of tax of $1,071 and $1,003, respectively	**1,630**	1,567
Total other comprehensive income (loss)	**2,273**	4,244
Comprehensive Income	**$ 40,016**	$ 18,968

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Operating Activities:		
Net income	**$ 37,743**	$ 14,724
Adjustments to reconcile net income		
to net cash provided from operating activities --		
Depreciation and amortization, total	**33,580**	32,355
Deferred income taxes	**8,601**	13,388
Convertible investment tax credits received	**38,068**	-
Deferred revenues	**(21,476)**	(20,993)
Mark-to-market adjustments	**(63)**	762
Other, net	**1,752**	930
Changes in certain current assets and liabilities --		
-Receivables	**20,759**	16,566
-Fossil fuel stock	**625**	3,815
-Materials and supplies	**253**	4,721
-Prepaid income taxes	**15,744**	(9,248)
-Other current assets	**(137)**	1,020
-Accounts payable	**(21,645)**	(15,111)
-Accrued taxes	**4,888**	3,433
-Accrued interest	**(12,281)**	(12,028)
-Other current liabilities	**(519)**	297
Net cash provided from operating activities	**105,892**	34,631
Investing Activities:		
Property additions	**(113,518)**	(68,179)
Change in construction payables	**43,259**	15,489
Payments pursuant to long-term service agreements	**(11,320)**	(8,145)
Other investing activities	**(3,165)**	(245)
Net cash used for investing activities	**(84,744)**	(61,080)
Financing Activities:		
Increase (decrease) in notes payable, net	**(20,360)**	48,006
Proceeds - Capital contributions	**17,179**	1,632
Repayments - Other long-term debt	**(3,066)**	-
Payment of common stock dividends	**(22,800)**	(26,775)
Other financing activities	**38**	95
Net cash provided from (used for) financing activities	**(29,009)**	22,958
Net Change in Cash and Cash Equivalents	**(7,861)**	(3,491)
Cash and Cash Equivalents at Beginning of Period	**14,204**	7,152
Cash and Cash Equivalents at End of Period	**$ 6,343**	$ 3,661
Supplemental Cash Flow Information:		
Cash paid during the period for --		
Interest (net of $4,240 and $1,926 capitalized for 2011 and 2010, respectively)	**$26,993**	$28,900
Income taxes (net of refunds)	**(44,721)**	1,532
Noncash transactions - accrued property additions at end of period	**78,567**	30,963

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Assets	**At March 31, 2011**	At December 31, 2010
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 6,343**	$ 14,204
Receivables --		
Customer accounts receivable	**65,359**	77,033
Other accounts receivable	**2,388**	1,979
Affiliated companies	**10,473**	19,673
Fossil fuel stock, at average cost	**13,209**	13,663
Materials and supplies, at average cost	**34,356**	33,934
Prepaid service agreements - current	**33,272**	41,627
Prepaid income taxes	**10,343**	53,860
Other prepaid expenses	**4,297**	4,161
Assets from risk management activities	**2,811**	2,160
Other current assets	**-**	19
Total current assets	**182,851**	262,313
Property, Plant, and Equipment:		
In service	**3,149,499**	3,143,919
Less accumulated provision for depreciation	**562,973**	536,107
Plant in service, net of depreciation	**2,586,526**	2,607,812
Construction work in progress	**538,067**	427,788
Total property, plant, and equipment	**3,124,593**	3,035,600
Other Property and Investments:		
Goodwill	**1,839**	1,839
Other intangible assets, net of amortization of $889 and $693 at March 31, 2011 and December 31, 2010, respectively	**48,231**	48,426
Total other property and investments	**50,070**	50,265
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	**80,134**	69,740
Other deferred charges and assets -- affiliated	**3,213**	3,275
Other deferred charges and assets -- non-affiliated	**20,214**	16,541
Total deferred charges and other assets	**103,561**	89,556
Total Assets	**$ 3,461,075**	$ 3,437,734

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At March 31, 2011**	At December 31, 2010
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 253**	$ -
Notes payable -- affiliated	**-**	65,883
Notes payable -- non-affiliated	**249,427**	203,904
Accounts payable --		
Affiliated	**46,536**	69,783
Other	**89,075**	45,985
Accrued taxes --		
Accrued income taxes	**2,390**	812
Other accrued taxes	**6,005**	2,775
Accrued interest	**17,696**	29,977
Liabilities from risk management activities	**5,553**	5,773
Other current liabilities	**3,512**	3,923
Total current liabilities	**420,447**	428,815
Long-term Debt	**1,299,364**	1,302,619
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**317,738**	307,989
Deferred convertible investment tax credits	**90,965**	80,401
Deferred capacity revenues -- affiliated	**9,763**	30,533
Other deferred credits and liabilities -- affiliated	**4,376**	4,635
Other deferred credits and liabilities -- non-affiliated	**17,450**	16,203
Total deferred credits and other liabilities	**440,292**	439,761
Total Liabilities	**2,160,103**	2,171,195
Redeemable Noncontrolling Interest	**3,357**	3,319
Common Stockholder's Equity:		
Common stock, par value $.01 per share --		
Authorized - 1,000,000 shares		
Outstanding - 1,000 shares	**-**	-
Paid-in capital	**918,148**	900,969
Retained earnings	**391,213**	376,270
Accumulated other comprehensive loss	**(11,746)**	(14,019)
Total common stockholder's equity	**1,297,615**	1,263,220
Total Liabilities and Stockholder's Equity	**$ 3,461,075**	$ 3,437,734

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

FIRST QUARTER 2011 vs. FIRST QUARTER 2010

OVERVIEW

Southern Power and its wholly-owned subsidiaries construct, acquire, own, and manage generation assets and sell electricity at market-based prices in the wholesale market. Southern Power continues to execute its strategy through a combination of acquiring and constructing new power plants and by entering into PPAs with investor owned utilities, independent power producers, municipalities, and electric cooperatives.

Effective March 15, 2011, Southern Company transferred its ownership in its wholly-owned subsidiary, Southern Renewable Energy, Inc. (SRE) to Southern Power. SRE was formed to construct, acquire, own, and manage renewable generation assets and sell electricity at market-based prices in the wholesale market. As a transfer of net assets among entities under common control, the assets and liabilities of SRE were transferred at historical cost. The consolidated financial statements of Southern Power have been revised to include the financial condition and the results of operations of SRE since its inception in January 2010.

To evaluate operating results and to ensure Southern Power's ability to meet its contractual commitments to customers, Southern Power focuses on several key performance indicators. These indicators include peak season equivalent forced outage rate (EFOR) and net income. EFOR defines the hours during peak demand times when Southern Power's generating units are not available due to forced outages (the lower the better). Net income is the primary measure of Southern Power's financial performance. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Southern Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$23.0	156.3

Southern Power's net income for the first quarter 2011 was $37.7 million compared to $14.7 million for the corresponding period in 2010. The increase was primarily due to higher energy and capacity revenues under new PPAs that began in June, July, and December 2010 and January 2011. The increase was partially offset by lower energy and capacity revenues under existing PPAs and the expiration of PPAs in May and December 2010, lower revenues from energy sales that were not covered by PPAs, higher other operations and maintenance expenses, and higher income taxes.

Wholesale Revenues – Non-Affiliates

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$43.9	28.6

Wholesale energy sales to non-affiliates will vary depending on the energy demand of those customers and their generation capacity, as well as the market cost of available energy compared to the cost of Southern Power's energy. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Wholesale revenues from non-affiliates for the first quarter 2011 were $197.2 million compared to $153.3 million for the corresponding period in 2010. The increase was mainly due to $88.1 million of energy and capacity revenues under new non-affiliate PPAs that began in June, July, and December 2010 and January 2011. These increases were partially offset by $31.0 million of lower revenues from energy sales that were not covered by PPAs as a result of significantly more favorable weather in the first quarter 2010 compared to 2011, and $13.3 million of lower energy and capacity revenues under existing non-affiliate PPAs and the expiration of a non-affiliate PPA in December 2010.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 of the Form 10-K for additional information.

Wholesale Revenues – Affiliates

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(18.5)	(18.2)

Wholesale energy sales to affiliated companies within the Southern Company system will vary depending on demand and the availability and cost of generating resources at each company. Sales to affiliate companies that are not covered by PPAs are made in accordance with the IIC, as approved by the FERC. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Wholesale revenues from affiliates for the first quarter 2011 were $83.3 million compared to $101.8 million for the corresponding period in 2010. The decrease was primarily the result of $27.4 million of lower energy and capacity revenues associated with the expiration of affiliate PPAs in May 2010 and $9.2 million related to lower revenues from power sales to affiliates under the IIC. These decreases were partially offset by $18.5 million of increased energy and capacity revenues associated with new affiliate PPAs that began in June 2010.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 of the Form 10-K for additional information.

Fuel and Purchased Power Expenses

First Quarter 2011 vs. First Quarter 2010		
	(change in millions)	*(% change)*
Fuel	$5.2	5.3
Purchased power – non-affiliates	(9.6)	(51.8)
Purchased power – affiliates	(8.3)	(35.5)
Total fuel and purchased power expenses	$(12.7)	

Southern Power PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in fuel costs is generally accompanied by an increase or decrease in related fuel revenues and does not have a significant impact on net income. Southern Power is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the market or sold to affiliates under the IIC.

In the first quarter 2011, total fuel and purchased power expenses were $126.8 million compared to $139.5 million for the corresponding period in 2010. Fuel and purchased power expenses decreased $42.9 million due to a 19.3% decrease in the average cost of natural gas and a 43.3% decrease in the average cost of purchased power. This decrease was partially offset by a $30.2 million increase in volume of KWHs generated and purchased.

In the first quarter 2011, fuel expense was $102.7 million compared to $97.5 million for the corresponding period in 2010. Fuel expense increased $29.7 million due to an increase in the volume of KWHs generated. This increase was partially offset by $24.5 million associated with a 19.3% decrease in the average cost of natural gas.

In the first quarter 2011, purchased power expense was $24.0 million compared to $41.9 million for the corresponding period in 2010. Purchased power expenses decreased $18.4 million due to a 43.3% decrease in the average cost of purchased power partially offset by $0.5 million associated with an increase in the volume of KWHs purchased.

Other Operations and Maintenance Expenses

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$3.7	9.6

In the first quarter 2011, other operations and maintenance expenses were $42.7 million compared to $39.0 million for the corresponding period in 2010. This increase was primarily due to a $4.8 million increase related to more generating plant scheduled outages in the first quarter 2011 compared to the corresponding period in 2010 and an unplanned outage at a combined cycle generating plant. These increases were partially offset by a $1.1 million decrease in salaries and wages relating mainly to higher payroll taxes in the first quarter of 2010.

Interest Expense, Net of Amounts Capitalized

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$(1.2)	(6.1)

In the first quarter 2011, interest expense, net of amounts capitalized was $18.8 million compared to $20.0 million for the corresponding period in 2010. The decrease was primarily due to an increase in capitalized interest associated with the construction of the Cleveland County combustion turbine units and the Nacogdoches biomass plant. See FUTURE EARNINGS POTENTIAL – "Construction Projects" herein for additional information.

Income Taxes

First Quarter 2011 vs. First Quarter 2010	
(change in millions)	*(% change)*
$11.4	120.8

In the first quarter 2011, income taxes were $20.8 million compared to $9.4 million for the corresponding period in 2010 primarily due to higher pre-tax earnings.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Southern Power's future earnings potential. The level of Southern Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Power's competitive wholesale business. These factors include Southern Power's ability to achieve sales growth while containing costs, regulatory matters, creditworthiness of customers, total generating capacity available in the Southeast, the successful remarketing of capacity as current contracts expire, and Southern Power's ability to execute its acquisition strategy and to construct generating facilities. Other factors that could influence future earnings include weather, demand, generation patterns, and operational limitations. Recessionary conditions have lowered demand and have negatively impacted capacity revenues under Southern Power's PPAs where the amounts purchased are based on demand. Southern Power is unable to predict whether demand under these PPAs will return to pre-recession levels. The timing and extent of the economic recovery is uncertain and will impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Southern Power in Item 7 of the Form 10-K.

Environmental Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 of the Form 10-K for information on the development by federal and state environmental regulatory agencies of additional control strategies for emissions of air pollution from industrial sources, including electric generating facilities. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, or other environmental and health concerns could also affect earnings. While Southern Power's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Carbon Dioxide Litigation

Kivalina Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" of Southern Power in Item 7 and Note 3 to the financial statements of Southern Power under "Environmental Matters – Carbon Dioxide Litigation – Kivalina Case" in Item 8 of the Form 10-K for additional information regarding carbon dioxide litigation. On February 23, 2011, the U.S. Court of Appeals for the Ninth Circuit issued an order staying the case until June 15, 2011. The ultimate outcome of this matter cannot be determined at this time.

Water Quality

On April 20, 2011, the EPA proposed a rule that establishes standards for reducing impacts to fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. The rule focuses on reducing adverse impacts to fish and other aquatic life due to impingement (when fish and other aquatic life are trapped by water flow velocity against a facility's cooling water intake structure screens) and entrainment (when aquatic organisms are drawn through a facility's cooling water system after entering through the cooling water intake structure). Affected cooling water intake structures would have to comply with national impingement standards (for intake velocity or alternatively numeric impingement reduction standards) and entrainment reduction requirements (determined on a case-by-case basis). The rule's proposed impingement standards could require technological improvements to cooling water intake structures at some of Southern Power's existing generating facilities, including facilities with closed-cycle re-circulating cooling systems (cooling towers). To address the rule's entrainment standards, facilities with once-through cooling systems may have to install cooling towers. New units constructed at existing plants would have to meet the national impingement standards and install closed-cycle cooling or the equivalent to meet the entrainment mandate. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of Southern Power's facilities may be subject to varying degrees of additional capital expenditures and compliance costs. While Southern Power's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Construction Projects

Cleveland County Units 1-4

In December 2008, Southern Power announced that it will build an electric generating plant in Cleveland County, North Carolina. The plant will consist of four combustion turbine natural gas generating units with a total generating capacity of 720 MWs. The units are expected to begin commercial operation in 2012. Costs incurred through March 31, 2011 were $239.2 million. The total estimated construction cost is expected to be between $350 million and $400 million.

Nacogdoches Biomass Plant

In October 2009, Southern Power acquired all of the outstanding membership interests of Nacogdoches Power LLC (Nacogdoches) from American Renewables LLC, the original developer of the project. Nacogdoches is constructing a biomass generating plant in Sacul, Texas with an estimated capacity of 100 MWs. The generating plant will be fueled from wood waste. Construction commenced in 2009 and the plant is expected to begin commercial operation in 2012. Costs incurred through March 31, 2011 were $296.1 million. The total estimated cost of the project is expected to be between $475 million and $500 million.

Other Matters

Southern Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Power is subject to certain claims and legal actions arising in the ordinary course of business. Southern Power's business activities are subject to extensive governmental regulation related to public health and the environment. 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 Southern Power and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Southern Power in Item 8 of the Form 10-K, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on Southern Power's financial statements.

See Note (B) to the Condensed Financial Statements herein for discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Power prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Southern Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Southern Power'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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Southern Power in Item 7 of the Form 10-K for a complete discussion of Southern Power's critical accounting policies and estimates related to Revenue Recognition, Impairment of Long Lived Assets and Intangibles, Acquisition Accounting, Contingent Obligations, Depreciation, and Convertible Investment Tax Credits (ITCs).

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Power's financial condition remained stable at March 31, 2011. Southern Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements as needed to meet future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $105.9 million for the first three months of 2011, compared to $34.6 million for the corresponding period in 2010. This increase was mainly due to an increase in cash received for convertible ITCs and bonus depreciation. Net cash used for investing activities totaled $84.7 million for the first three months of 2011, compared to $61.1 million for the corresponding period in 2010. This increase was primarily due to an increase in construction work in progress related to construction activities at Cleveland County and Nacogdoches. Net cash used for financing activities totaled $29.0 million for the first three months of 2011, compared to $23.0 million cash provided from financing activities for the corresponding period in 2010 primarily due to repayment of an affiliate loan related to SRE.

Significant asset changes in the balance sheet for the first quarter 2011 include an increase in construction work in progress due to Cleveland County and Nacogdoches construction activities and a decrease in prepaid income taxes mainly due to the receipt of an income tax refund from the IRS related to convertible ITCs and bonus depreciation.

Significant liability and stockholder's equity changes in the balance sheet for the first quarter 2011 include an increase in accounts payable – other primarily related to Cleveland County and Nacogdoches construction activities, a decrease in accounts payable – affiliated primarily due to the expiration of affiliate PPAs in May 2010, a decrease in notes payable primarily due to repayment of an affiliate loan related to SRE, and a decrease in deferred capacity revenues – affiliated primarily due to seasonality.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Power in Item 7 of the Form 10-K for a description of Southern Power's capital requirements for its construction program, scheduled maturities of long-term debt, interest, leases, derivative obligations, purchase commitments, and long-term service agreements. The construction program is subject to periodic review and revision; these amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements. Planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

Sources of Capital

Southern Power may use operating cash flows, external funds, equity capital, or loans from Southern Company to finance any new projects, acquisitions, and ongoing capital requirements. Southern Power expects to generate external funds from the issuance of unsecured senior debt and commercial paper or utilization of credit arrangements from banks. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Southern Power in Item 7 of the Form 10-K for additional information.

Southern Power's current liabilities frequently exceed current assets due to the use of short-term indebtedness as a funding source to meet cash needs which can fluctuate significantly due to the seasonality of the business. To meet liquidity and capital resource requirements, Southern Power had at March 31, 2011 cash and cash equivalents of approximately $6 million and committed credit arrangements with banks of $400 million, all of which expire in 2012. Proceeds from these credit arrangements may be used for working capital and general corporate purposes as well as liquidity support for Southern Power's commercial paper program. See Note 6 to the financial statements of Southern Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information. Southern Power's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. At March 31, 2011, Southern Power had $249 million of commercial paper borrowings outstanding with a weighted average interest rate of 0.4% per annum. During the first quarter 2011, Southern Power had an average of $231 million of commercial paper outstanding at a weighted average interest rate of 0.4% per annum and the maximum amount outstanding was $272 million. Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Credit Rating Risk

Southern Power 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 Baa2, or 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 March 31, 2011, the maximum potential collateral requirements under these contracts at a BBB and Baa2 rating were approximately $9 million and at a BBB- and/or Baa3 rating were approximately $367 million. At March 31, 2011, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $1.0 billion. 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 Southern Power's ability to access capital markets, particularly the short-term debt market.

In addition, through the acquisition of Plant Rowan, Southern Power assumed PPAs with Duke Energy and North Carolina Municipal Power Agency No. 1 (NCMPA1) that could require collateral, but not accelerated payment, in the event of a downgrade of Southern Power's credit. The Duke Energy PPA defines the downgrade to be below BBB- or Baa3. The NCMPA1 PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade for both PPAs.

Market Price Risk

Southern Power is exposed to market risks, including changes in interest rates, certain energy-related commodity prices, and, occasionally, currency exchange rates. To manage the volatility attributable to these exposures, Southern Power takes advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to Southern Power's policies in areas such as counterparty exposure and risk management practices. Southern Power'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 tests, and sensitivity analysis.

Southern Power's market risk exposure relative to interest rate changes for the first quarter 2011 has not changed materially compared with the December 31, 2010 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, Southern Power is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Because energy from Southern Power's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

The changes in fair value of energy-related derivative contracts for the three months ended March 31, 2011 were as follows:

	First Quarter 2011 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(3.5)
Contracts realized or settled	0.7
Current period changes[(a)]	0.5
Contracts outstanding at the end of the period, assets (liabilities), net	$(2.3)

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

The increase in the fair value positions of the energy-related derivative contracts for the three months ended March 31, 2011 was $1.2 million, which is due to both power and natural gas positions. This change is attributable to both the volume and prices of power and natural gas as follows:

	March 31, 2011	**December 31, 2010**
Power (net sold)		
MWHs *(in millions)*	0.8	0.9
Weighted average contract cost per MWH above (below) market prices *(in dollars)*	$(3.20)	$(2.33)
Natural gas (net purchase)		
Commodity – million mmBtu	13.5	13.0
Commodity – Weighted average contract cost per mmBtu above (below) market prices *(in dollars)*	$ 0.01	$ 0.11

The fair value of energy-related derivative contracts by hedge designation reflected in the financial statements as assets (liabilities) consists of the following:

Asset (Liability) Derivatives	**March 31, 2011**	**December 31, 2010**
	(in millions)	
Cash flow hedges	$0.1	$(1.0)
Not designated	(2.4)	(2.5)
Total fair value	$(2.3)	$(3.5)

Gains and losses on energy-related derivatives used by Southern Power to hedge anticipated purchases and sales are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Total net unrealized pre-tax gains (losses) recognized in the statements of income for the three months ended March 31, 2011 for energy-related derivative contracts that were not hedges were not material and will continue to be marked to market until the settlement date. For the three months ended March 31, 2010, the total net unrealized pre-tax losses recognized in the statements of income were $0.7 million.

Southern Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2011 were as follows:

	March 31, 2011 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ -	$ -	$-	$ -
Level 2	(2.3)	(2.7)	-	0.4
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(2.3)	$(2.7)	$-	$0.4

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 Southern Power. 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.

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Southern Power in Item 7 and Note 1 under "Financial Instruments" and Note 9 to the financial statements of Southern Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

During the three months ended March 31, 2011, Southern Power paid $3.1 million on a long-term loan related to SRE. Southern Power did not issue or redeem any long-term securities during the first quarter 2011.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS
FOR
THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
ALABAMA POWER COMPANY
GEORGIA POWER COMPANY
GULF POWER COMPANY
MISSISSIPPI POWER COMPANY
SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES

INDEX TO APPLICABLE NOTES TO
FINANCIAL STATEMENTS BY REGISTRANT

Registrant	**Applicable Notes**
Southern Company	A, B, C, D, E, F, G, H, I
Alabama Power	A, B, C, E, F, G, H
Georgia Power	A, B, C, E, F, G, H
Gulf Power	A, B, C, E, F, G, H
Mississippi Power	A, B, C, E, F, G, H
Southern Power	A, B, C, E, G, H

NOTES TO THE CONDENSED FINANCIAL STATEMENTS:

(A) INTRODUCTION
The condensed quarterly financial statements of each registrant included herein have been prepared by such registrant, without audit, pursuant to the rules and regulations of the SEC. The Condensed Balance Sheets as of December 31, 2010 have been derived from the audited financial statements of each registrant. In the opinion of each registrant's management, the information regarding such registrant furnished herein reflects all adjustments, which, except as otherwise disclosed, are of a normal recurring nature, necessary to present fairly the results of operations for the periods ended March 31, 2011 and 2010. Certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations, although each registrant believes that the disclosures regarding such registrant are adequate to make the information presented not misleading. Disclosures which would substantially duplicate the disclosures in the Form 10-K and details which have not changed significantly in amount or composition since the filing of the Form 10-K are generally omitted from this Quarterly Report on Form 10-Q. Therefore, these Condensed Financial Statements should be read in conjunction with the financial statements and the notes thereto included in the Form 10-K. Due to the seasonal variations in the demand for energy, operating results for the periods presented are not necessarily indicative of the operating results to be expected for the full year.

Effective March 15, 2011, Southern Company transferred its ownership in its wholly-owned subsidiary, Southern Renewable Energy, Inc. (SRE), to Southern Power. SRE was formed to construct, acquire, own, and manage renewable generation assets and sell electricity at market-based prices in the wholesale market. As a transfer of net assets among entities under common control, the assets and liabilities of SRE were transferred at historical cost. The consolidated financial statements of Southern Power have been revised to include the financial condition and the results of operations of SRE since its inception in January 2010.

Southern Company has made separate guarantees to two counterparties regarding performance of contractual commitments by SRE. The total original notional amount of the guarantees was $120 million, approximately $12 million of which was outstanding at March 31, 2011. Of this amount, approximately $3 million is expected to expire in August 2011, and approximately $9 million is expected to expire in 2037.

Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

(B) CONTINGENCIES AND REGULATORY MATTERS
See Note 3 to the financial statements of the registrants in Item 8 of the Form 10-K for information relating to various lawsuits, other contingencies, and regulatory matters.

General Litigation Matters

Each registrant is subject to certain claims and legal actions arising in the ordinary course of business. In addition, each registrant'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 each registrant and any of its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of each registrant in Item 8 of the Form 10-K, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on such registrant'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 NSR provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. 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 facilities co-owned by Mississippi Power and Gulf Power. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The EPA concurrently issued notices of violation to Gulf Power and Mississippi Power relating to Gulf Power's Plant Crist and Mississippi Power's Plant Watson. In early 2000, the EPA filed a motion to amend its complaint to add Gulf Power and Mississippi Power as defendants based on the allegations in the notices of violation. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not re-filed. The action against Georgia Power has been administratively closed since the spring of 2001, and the case has not been reopened. The separate action against Alabama Power is ongoing.

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.

In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims for summary disposition or trial, including the claim relating to a facility co-owned by Mississippi Power. The parties each filed motions for summary judgment in September 2010.

On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power's motion for summary judgment on all remaining claims and dismissed the case with prejudice. The EPA has the right to appeal within 60 days of the order.

Southern Company believes that the traditional operating companies 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 these matters cannot be determined at this time.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from several 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. In December 2010, the U.S. Supreme Court granted the defendants' petition for writ of certiorari. On April 19, 2011, the U.S. Supreme Court heard oral argument in this case, and a decision is expected before year-end. 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. On February 23, 2011, the U.S. Court of Appeals for the Ninth Circuit issued an order staying the case until June 15, 2011. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The registrants 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 subsidiaries may also incur substantial costs to clean up properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. Within limits approved by the state PSCs, these rates are adjusted annually or as necessary.

Georgia Power's environmental remediation liability as of March 31, 2011 was $13.2 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and CERCLA NPL are anticipated; however, they are not expected to have a material impact on Georgia Power's or Southern Company's financial statements.

In September 2008, the EPA advised Georgia Power that it has been designated as a PRP at the Ward Transformer Superfund site located in Raleigh, North Carolina. Numerous other entities have also received notices regarding this site from the EPA. Georgia Power, along with other named PRPs, is negotiating with the EPA to address cleanup of the site and reimbursement for past expenditures related to work performed at the site. In addition, in April 2009, two PRPs filed separate actions in the U.S. District Court for the Eastern District of North Carolina against numerous other PRPs, including Georgia Power, seeking contribution from the defendants for expenses incurred by the plaintiffs related to work performed at a portion of the site. The ultimate outcome of these matters will depend upon further environmental assessment and the ultimate number of PRPs and cannot be determined at this time; however, it is not expected to have a material impact on Southern Company's and Georgia Power's financial statements.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $63.5 million as of March 31, 2011. 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 Gulf Power 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 Gulf Power's environmental cost recovery clause; therefore, there was no impact on net income as a result of these estimates.

In 2003, the Texas Commission on Environmental Quality (TCEQ) designated Mississippi Power as a PRP at a site in Texas. The site was owned by an electric transformer company that handled Mississippi Power's transformers as well as those of many other entities. The site owner is bankrupt and the State of Texas has entered into an agreement with Mississippi Power and several other utilities to investigate and remediate the site. Amounts expensed during the first quarters of 2010 and 2011 related to this work were not material. Hundreds of entities have received notices from the TCEQ requesting their participation in the anticipated site remediation. The final impact of this matter will depend upon further environmental assessment and the ultimate number of PRPs. The remediation expenses incurred by Mississippi Power are expected to be recovered through the ECO Plan.

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, Southern Company, Georgia Power, Gulf Power, and Mississippi Power do not believe that additional liabilities, if any, at these sites would be material to their respective financial statements.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including Mississippi Power, have been named as defendants in numerous lawsuits brought by landowners since 2001. The plaintiffs' lawsuits claim that defendants may not use, or sublease to third parties, some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties and that such actions exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment and seek compensatory and punitive damages and injunctive relief. Management of Southern Company and Mississippi Power believe they have complied with applicable laws and that the plaintiffs' claims are without merit.

Mississippi Power has entered into agreements with plaintiffs in approximately 95% of the actions pending against Mississippi Power to clarify its easement rights in the State of Mississippi. These agreements have been approved by the Circuit Courts of Harrison County and Jasper County, Mississippi (First Judicial Circuit), and the related cases have been dismissed. These agreements have not resulted in any material effects on Southern Company's or Mississippi Power's financial statements.

In addition, in late 2001, certain subsidiaries of Southern Company, including Mississippi Power, were named as defendants in a lawsuit brought in Troup County, Georgia, Superior Court by Interstate Fiber Network Inc. a subsidiary of telecommunications company ITC DeltaCom, Inc. that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. Southern Company and Mississippi Power believe that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. In August 2010, the defendants filed a motion to dismiss the suit for lack of prosecution. The court denied the defendants' motion to dismiss the claim. On March 25, 2011, the plaintiffs filed an amended complaint asserting claims for breach of contract for failing to make the defendants' facilities fully available to the plaintiffs and for failing to indemnify the plaintiffs in defending the underlying landowner litigation. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Nuclear Fuel Disposal Cost Litigation

See Note 3 to the financial statements of Southern Company, Alabama Power, and Georgia Power under "Nuclear Fuel Disposal Costs" in Item 8 of the Form 10-K for information regarding the litigation brought by Alabama Power and Georgia Power against the government for breach of contracts related to the disposal of spent nuclear fuel.

In July 2007, the U.S. Court of Federal Claims awarded Georgia Power approximately $30 million, based on its ownership interests, and awarded Alabama Power approximately $17 million, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plants Farley, Hatch, and Vogtle from 1998 through 2004. In November 2007, the government's motion for reconsideration was denied. In January 2008, the government filed an appeal and, in February 2008, filed a motion to stay the appeal, which the U.S. Court of Appeals for the Federal Circuit granted in April 2008. In May 2010, the U.S. Court of Appeals for the Federal Circuit lifted the stay.

On March 11, 2011, the U.S. Court of Appeals for the Federal Circuit issued an order in which it affirmed the damage award to Alabama Power, but remanded the Georgia Power portion of the proceeding back to the U.S. Court of Federal Claims for reconsideration of the damages amount in light of the spent nuclear fuel acceptance rates adopted in a separate proceeding by the U.S. Court of Appeals for the Federal Circuit.

In April 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim), due to the government's alleged continuing breach of contract. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of March 31, 2011 for either claim. The final outcome of these matters cannot be determined at this time, but no material impact on net income is expected as any damage amounts collected from the government are expected to be returned to customers.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plants Hatch and Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of each plant.

Income Tax Matters

Georgia State Income Tax Credits

Georgia Power's 2005 through 2009 income tax filings for the State of Georgia include state income tax credits for increased activity through Georgia ports. Georgia Power also filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue (DOR) has not responded to these claims. In July 2007, Georgia Power filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. In March 2010, the Superior Court of Fulton County ruled in favor of Georgia Power's motion for summary judgment. The Georgia DOR has appealed to the Georgia Court of Appeals and a decision is expected later this year. Any decision may be subject to further appeal to the Georgia Supreme Court. An unrecognized tax benefit has been recorded related to these credits. If Georgia Power prevails, no material impact on Southern Company's or Georgia Power's net income is expected as a significant portion of any tax benefit is expected to be returned to retail customers in accordance with the 2010 ARP. If Georgia Power is not successful, payment of the related state tax for previously utilized credits would have a negative effect on Southern Company's and Georgia Power's cash flow. See Note 5 to the financial statements of Southern Company and Georgia Power in Item 8 of the Form 10-K under "Unrecognized Tax Benefits" and Note (G) herein for additional information. The ultimate outcome of this matter cannot now be determined.

State PSC Matters

Alabama Power

Natural Disaster Reserve

See Note 3 to the financial statements of Southern Company under "PSC Matters – Alabama Power – Natural Disaster Reserve" and Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters – Natural Disaster Reserve" in Item 8 of the Form 10-K for additional information. At March 31, 2011, the NDR had an accumulated balance of $127 million, which is included in the Condensed Balance Sheets herein under other regulatory liabilities, deferred. The accruals are reflected as operations and maintenance expenses in the Condensed Statements of Income herein.

On April 27, 2011, devastating storms swept through the central part of Alabama causing significant damage in parts of Alabama Power's service territory. Over 400,000 of Alabama Power's 1.4 million customers were without electrical service immediately after the storms, resulting from significant damage to Alabama Power's transmission and distribution facilities. The preliminary estimated cost associated with repairing the damage to facilities and restoring electrical service to customers is between $40 million and $55 million for operations and maintenance expenses and between $180 million and $225 million for capital expenditures. Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to Alabama Power's transmission and distribution facilities.

Georgia Power

Fuel Cost Recovery

See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" and "Retail Regulatory Matters – Fuel Cost Recovery," respectively, in Item 8 of the Form 10-K for additional information. On March 1, 2011, Georgia Power filed a request with the Georgia PSC to decrease fuel rates by 0.61%. The decrease would reduce Georgia Power's annual billings by approximately $43 million. The decrease in fuel costs is driven primarily by lower natural gas prices than those included in current rates as a result of increases in natural gas supplies from the production of shale gas and lower industrial demand. If approved, the new rates will go into effect June 1, 2011. The ultimate outcome of this matter cannot be determined at this time.

Nuclear Construction

See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Construction – Nuclear," respectively, in Item 8 of the Form 10-K for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4.

In December 2010, Westinghouse submitted an AP1000 Design Certification Amendment (DCA) to the NRC. On February 10, 2011, the NRC announced that it was seeking public comment on a proposed rule to approve the DCA and amend the certified AP1000 reactor design for use in the U.S. The Advisory Committee on Reactor Safeguards also issued a letter on January 24, 2011 endorsing the issuance of the Construction and Operating License (COL) for Plant Vogtle Units 3 and 4. In addition, on March 25, 2011, the NRC submitted to the EPA the final environmental impact statement for Plant Vogtle Units 3 and 4. Georgia Power currently expects to receive the COL for Plant Vogtle Units 3 and 4 from the NRC in late 2011 based on the NRC's February 16, 2011 release of its COL schedule framework.

On February 21, 2011, the Georgia PSC voted to approve Georgia Power's third semi-annual construction monitoring report including total costs of $1.048 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2010. In connection with its certification of Plant Vogtle Units 3 and 4, the Georgia PSC ordered Georgia Power and the PSC Staff to work together to develop a risk sharing or incentive mechanism that would provide some level of protection to ratepayers in the event of significant cost overruns, but also not penalize Georgia Power's earnings if and when overruns are due to mandates from governing agencies. Such discussions have continued through the third semi-annual construction monitoring proceedings; however, the Georgia PSC has deferred a decision with respect to any related risk-sharing or incentive mechanism. A Georgia PSC hearing on this matter is scheduled on July 6, 2011 and a decision is expected on August 2, 2011. Georgia Power will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In December 2010, the Georgia PSC approved Georgia Power's NCCR tariff, which became effective January 1, 2011. The NCCR tariff was established to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period in accordance with the Georgia Nuclear Energy Financing Act. With respect to Plant Vogtle Units 3 and 4, this legislation allows Georgia Power to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. Georgia Power is collecting and amortizing to earnings approximately $91 million of financing costs capitalized in 2009 and 2010 over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At March 31, 2011, approximately $87 million of these 2009 and 2010 costs are included in construction work in progress.

Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), and a consortium consisting of Westinghouse and Stone & Webster, Inc. have established both informal and formal dispute resolution procedures in order to resolve issues that commonly arise during the course of constructing a project of this magnitude. Southern Nuclear, on behalf of the Owners, has initiated both formal and informal claims through these procedures, including ongoing claims, and anticipates that further issues are likely to arise in the future. The Owners have successfully used both the informal and formal procedures to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

There are other pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, including petitions filed at the NRC in response to the events in Japan. Similar additional challenges at the state and federal level are expected as construction proceeds.

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

Other Construction

In May 2010, the Georgia PSC approved Georgia Power's request to extend the construction schedule for Plant McDonough Units 4, 5, and 6 as a result of the short-term reduction in forecasted demand, as well as the requested increase in the certified amount. As a result, the units are expected to be placed into service in January 2012, May 2012, and January 2013, respectively. The Georgia PSC has approved Georgia Power's quarterly construction monitoring reports, including actual project expenditures incurred, through June 30, 2010. Georgia Power will continue to file quarterly construction monitoring reports throughout the construction period.

Plant Branch Units 1 and 2 De-certification

On March 22, 2011, the board of the Georgia Department of Natural Resources began consideration of modifications to the Georgia Multi-Pollutant Rule. The proposed modifications would change the compliance dates for certain of Georgia Power's coal-fired generating units as follows:

Scherer 3	July 1, 2011
Branch 1	December 31, 2013
Branch 2	October 1, 2013
Branch 3	October 1, 2015
Branch 4	December 31, 2015

The Multi-Pollutant Rule is designed to reduce emissions of mercury, sulfur dioxide, and nitrogen oxides statewide. The Utility Maximum Achievable Control Technology rule will also regulate emissions of mercury, in addition to other air pollutants. All required controls, including SCR, scrubber, and baghouse, are expected to be operational at Plant Scherer Unit 3 by the required compliance date. As a result of these proposed rules, Georgia Power's management expects to request that the Georgia PSC approve de-certification of its Plant Branch Units 1 and 2, totaling 569 MWs of capacity, as of the effective dates for controls under the Multi-Pollutant Rule as revised. Georgia Power continues to analyze the potential costs and benefits of installing the required controls on its remaining coal-fired units, including Plant Branch Units 3 and 4, in light of the proposed air quality rules, as well as additional potential federal regulations related to water quality and coal combustion byproducts. Georgia Power may determine that retiring and replacing certain of its existing units with new generating resources or purchased power is more economically efficient than installing the required controls.

See Note 3 under "Retail Regulatory Matters – Rate Plans" to the financial statements of Southern Company and Georgia Power in Item 8 of the Form 10-K for information regarding the 2010 ARP. Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated integrated resource plan will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. Georgia Power currently expects to file an update to its integrated resource plan in late summer 2011, which would include the Plant Branch Units 1 and 2 de-certification request. In connection with this filing, Georgia Power expects to request the Georgia PSC to approve the deferral and related amortization of the retail portion of the related costs associated with the de-certification request. Georgia Power moved the retail portion of the net carrying value of Plant Branch Units 1 and 2 from plant in service, net of depreciation, to other utility plant, net of depreciation. Consistent with current ratemaking treatment, Georgia Power will continue to depreciate these units using the composite straight-line rates approved by the Georgia PSC, and upon actual retirement, expects to include the units' remaining net carrying value in rate base. However, the recovery periods for these units may change in connection with Georgia Power's updated integrated resource plan. As a result of this regulatory treatment, the de-certification of Plant Branch Units 1 and 2 is not expected to have a significant impact on Southern Company's or Georgia Power's financial statements.

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

Gulf Power

Energy Conservation Cost Recovery

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

The most recent goal setting process established new DSM goals for the period 2010-2019. The new goals are significantly larger than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. Throughout 2010, Gulf Power engaged in a process at the Florida PSC to develop plans and programs to meet the new DSM goals. The DSM program standards were approved in April 2011, which allow Gulf Power to implement its DSM programs designed to meet the new goals. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

Mississippi Power

Certificated New Plant

On April 27, 2011, Mississippi Power submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-A (CNP-A), a new proposed cost recovery mechanism designed specifically to recover financing costs during the construction phase of the Kemper IGCC. Annual CNP-A rate filings would be made with the first filing occurring in November 2011. If approved by the Mississippi PSC, recovery through CNP-A will remain in place thereafter until the end of the calendar year that the Kemper IGCC is placed into commercial service, which is projected to be 2014. Certificated New Plant-B, which will be filed at a later date, would propose to govern rates effective from the first calendar year after the Kemper IGCC is placed into commercial service through the first seven full calendar years of its operation. The ultimate outcome of this matter cannot be determined at this time.

Integrated Coal Gasification Combined Cycle

See Note 3 to the financial statements of Southern Company under “Retail Regulatory Matters – Mississippi Power Integrated Coal Gasification Combined Cycle” and of Mississippi Power under “Integrated Coal Gasification Combined Cycle” in Item 8 of the Form 10-K for information regarding Mississippi Power’s construction of the Kemper IGCC.

In June 2010, the Mississippi Chapter of the Sierra Club (Sierra Club) filed an appeal of the Mississippi PSC’s June 3, 2010 decision to grant the Certificate of Public Convenience and Necessity for the Kemper IGCC with the Chancery Court of Harrison County, Mississippi (Chancery Court). Subsequently, in July 2010, the Sierra Club also filed an appeal directly with the Mississippi Supreme Court. In October 2010, the Mississippi Supreme Court dismissed the Sierra Club’s direct appeal. On February 28, 2011, the Chancery Court issued a judgment affirming the Mississippi PSC’s order authorizing the construction of the Kemper IGCC. On March 1, 2011, the Sierra Club appealed the Chancery Court’s decision to the Mississippi Supreme Court.

In May 2009, Mississippi Power received notification from the IRS formally certifying the IRS allocated Internal Revenue Code Section 48A tax credits (Phase I) of $133 million to Mississippi Power. On April 19, 2011, Mississippi Power received notification from the IRS formally certifying that the IRS allocated $279 million of Internal Revenue Code Section 48A tax credits (Phase II) to Mississippi Power. The utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II tax credits, Mississippi Power plans to capture and sequester (via enhanced oil recovery) at least 65% of the carbon dioxide (CO_2) produced by the plant during operations in accordance with the recapture rules for Section 48A investment tax credits. Through March 31, 2011, Mississippi Power received and accrued tax benefits totaling $31.9 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC.

In February 2008, Mississippi Power requested that the DOE transfer the remaining funds previously granted under the Clean Coal Power Initiative Round 2 (CCPI2) from a cancelled IGCC project of one of Southern Company’s subsidiaries that would have been located in Orlando, Florida. In December 2008, an agreement was reached to assign the remaining funds ($270 million) to the Kemper IGCC. Mississippi Power will receive grant funds of $245 million during the construction of the plant and $25 million during the initial operation of the plant. Through March 31, 2011, Mississippi Power has received $40 million and requested an additional $20.1 million associated with this grant.

On March 10, 2011, the Sierra Club filed a lawsuit in the U.S. District Court for the District of Columbia against the DOE regarding the National Environmental Policy Act review process asking for a stay on the issuance of CCPI2 funds and a stay to any related construction activities. On May 5, 2011, Mississippi Power filed a motion to intervene in this lawsuit.

In March 2010, the Mississippi Department of Environmental Quality (MDEQ) issued the Prevention of Significant Deterioration (PSD) air permit modification for the plant, which modifies the original PSD air permit issued in October 2008. The Sierra Club requested a formal evidentiary hearing regarding the issuance of the modified permit. On April 4, 2011, the MDEQ Permit Board held an evidentiary hearing wherein the permit board unanimously affirmed the PSD air permit.

On March 4, 2011, Mississippi Power and Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., entered into a contract in which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC.

On April 27, 2011, Mississippi Power submitted to the Mississippi PSC a proposed rate schedule detailing CNP-A, a new proposed cost recovery mechanism designed specifically to recover financing cost during the construction phase of the Kemper IGCC. See “Certificated New Plant” herein for additional information.

As of March 31, 2011, Mississippi Power had spent a total of $352.8 million on the Kemper IGCC, including regulatory filing costs. Of this total, $277 million was included in CWIP (net of $60.1 million of CCPI2 grant funds), $13.2 million was recorded in other regulatory assets, $1.5 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed.

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

(C) FAIR VALUE MEASUREMENTS

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

	Fair Value Measurements Using			
As of March 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Southern Company				
Assets:				
Energy-related derivatives	$ -	$ 14	$ -	$ 14
Interest rate derivatives	-	9	-	9
Foreign currency derivatives	-	6	-	6
Nuclear decommissioning trusts[(a)]	631	738	-	1,369
Cash equivalents and restricted cash	262	-	-	262
Other investments	12	49	12	73
Total	$ 905	$ 816	$ 12	$ 1,733
Liabilities:				
Energy-related derivatives	$ -	$ 172	$ -	$ 172
Interest rate derivatives	-	1	-	1
Total	$ -	$ 173	$ -	$ 173
Alabama Power				
Assets:				
Energy-related derivatives	$ -	$ 2	$ -	$ 2
Nuclear decommissioning trusts:[(b)]				
Domestic equity	328	61	-	389
Foreign equity	7	7	-	14
U.S. Treasury and government agency securities	19	8	-	27
Corporate bonds	-	83	-	83
Mortgage and asset backed securities	-	29	-	29
Other	28	8	-	36
Cash equivalents and restricted cash	71	-	-	71
Total	$ 453	$ 198	$ -	$ 651
Liabilities:				
Energy-related derivatives	$ -	$ 29	$ -	$ 29

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

As of March 31, 2011:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Georgia Power				
Assets:				
Energy-related derivatives	$ -	$ 2	$-	$ 2
Nuclear decommissioning trusts:[c]				
Domestic equity	249	1	-	250
U.S. Treasury and government agency securities	-	87	-	87
Municipal bonds	-	60	-	60
Corporate bonds	-	211	-	211
Mortgage and asset backed securities	-	115	-	115
Other	-	68	-	68
Total	$249	$544	$-	$793
Liabilities:				
Energy-related derivatives	$ -	$ 86	$-	$ 86
Gulf Power				
Assets:				
Energy-related derivatives	$ -	$ 3	$-	$ 3
Cash equivalents	14	-	-	14
Total	$ 14	$ 3	$-	$ 17
Liabilities:				
Energy-related derivatives	$ -	$ 11	$-	$ 11
Mississippi Power				
Assets:				
Energy-related derivatives	$ -	$ 3	$-	$ 3
Foreign currency derivatives	-	6	-	6
Cash equivalents	68	-	-	68
Total	$ 68	$ 9	$-	$ 77
Liabilities:				
Energy-related derivatives	$ -	$ 40	$-	$ 40
Southern Power				
Assets:				
Energy-related derivatives	$ -	$ 4	$-	$ 4
Liabilities:				
Energy-related derivatives	$ -	$ 6	$-	$ 6

(a) For additional detail, see the nuclear decommissioning trusts sections for Alabama Power and Georgia Power in this table.

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

(c) Includes the investment securities pledged to creditors and cash collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the securities lending program. As of March 31, 2011, approximately $99 million of the fair market value of Georgia Power's nuclear decommissioning trust funds' securities were on loan and pledged to creditors under the funds' managers' securities lending program.

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 LIBOR interest rates. Interest rate and foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. Inputs for foreign currency derivatives are from observable market sources. See Note (H) herein for additional information on how these derivatives are used.

"Other investments" include investments in funds that are valued using the market approach and income approach. Securities that are traded in the open market are valued at the closing price on their principal exchange as of the measurement date. Discounts are applied in accordance with GAAP when certain trading restrictions exist. For investments that are not traded in the open market, the price paid will have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan execution. As the investments mature or if market conditions change materially, further analysis of the fair market value of the investment is performed. This analysis is typically based on a metric, such as multiple of earnings, revenues, earnings before interest and income taxes, or earnings adjusted for certain cash changes. These multiples are based on comparable multiples for publicly traded companies or other relevant prior transactions.

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

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

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

As of March 31, 2011:	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
Southern Company				
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$100	None	Daily	1 to 3 days
Other – commingled funds	68	None	Daily	Not applicable
Trust owned life insurance	89	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	262	None	Daily	Not applicable
Other:				
Money market funds	2	None	Daily	Not applicable
Alabama Power				
Nuclear decommissioning trusts:				
Trust owned life insurance	$89	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	71	None	Daily	Not applicable
Georgia Power				
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$100	None	Daily	1 to 3 days
Other – commingled funds	68	None	Daily	Not applicable
Gulf Power				
Cash equivalents:				
Money market funds	$14	None	Daily	Not applicable
Mississippi Power				
Cash equivalents:				
Money market funds	$68	None	Daily	Not applicable

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (the Funds) to comply with the NRC's regulations. The commingled funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio of high grade money market instruments, including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations having a maximum five-year final maturity with put features or floating rates with a reset rate date of 13 months or less. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The corporate bonds – commingled funds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 to the financial statements of Southern Company and Georgia Power under "Nuclear Decommissioning" in Item 8 of the Form 10-K for additional information.

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

Southern Company, Alabama Power, and Georgia Power continue to elect the option to fair value investment securities held in the nuclear decommissioning trust funds. For the three months ended March 31, 2011, the increase in fair value of the funds, which includes reinvested interest and dividends, is recorded in the regulatory liability and was $27.3 million for Alabama Power, $14.6 million for Georgia Power, and $41.9 million for Southern Company.

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 investment in the money market funds.

Changes in the fair value measurement of the Level 3 items using significant unobservable inputs for Southern Company at March 31, 2011 were as follows:

	Level 3
	Other
	(in millions)
Beginning balance at December 31, 2010	$19
Purchases	1
Total gains (losses) – realized/unrealized:	
Included in earnings	(5)
Included in OCI	(3)
Ending balance at March 31, 2011	**$12**

At March 31, 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
Southern Company	$19,418	$20,100
Alabama Power	$ 6,235	$ 6,538
Georgia Power	$ 8,437	$ 8,641
Gulf Power	$ 1,224	$ 1,259
Mississippi Power	$ 586	$ 608
Southern Power	$ 1,299	$ 1,382

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

(D) STOCKHOLDERS' EQUITY

Earnings per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. See Note 8 to the financial statements of Southern Company in Item 8 of the Form 10-K for further information on the stock option and performance share plans. The effects of both stock options and performance share award units were determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(in thousands)	
As reported shares	**847,510**	822,526
Effect of options	**6,429**	2,261
Diluted shares	**853,939**	824,787

Stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive were 7 million and 25 million for the three months ended March 31, 2011 and March 31, 2010, respectively. Assuming an average stock price of $38.01 (the highest exercise price of the anti-dilutive options outstanding), the effect of options would have been immaterial for the three months ended March 31, 2011 and would have increased by 2 million shares for the three months ended March 31, 2010.

Changes in Stockholders' Equity

The following table presents year-to-date changes in stockholders' equity of Southern Company:

	Number of Common Shares		Common Stockholders' Equity	Preferred and Preference Stock of Subsidiaries	Total Stockholders' Equity
	Issued	Treasury			
	(in thousands)			*(in millions)*	
Balance at December 31, 2010	843,814	(474)	$16,202	$707	$16,909
Net income after dividends on preferred and preference stock	-	-	422	-	422
Other comprehensive income (loss)	-	-	4	-	4
Stock issued	5,784	-	222	-	222
Cash dividends on common stock	-	-	(385)	-	(385)
Other	-	(1)	-	-	-
Balance at March 31, 2011	849,598	(475)	$16,465	$707	$17,172
Balance at December 31, 2009	820,152	(505)	$14,878	$707	$15,585
Net income after dividends on preferred and preference stock	-	-	495	-	495
Other comprehensive income (loss)	-	-	9	-	9
Stock issued	4,872	-	171	-	171
Cash dividends on common stock	-	-	(359)	-	(359)
Other	-	17	1	-	1
Balance at March 31, 2010	825,024	(488)	$15,195	$707	$15,902

(E) FINANCING

Bank Credit Arrangements

Bank credit arrangements provide liquidity support to the registrants' commercial paper borrowings and the traditional operating companies' variable rate pollution control revenue bonds. See Note 6 to the financial statements of each registrant under "Bank Credit Arrangements" in Item 8 of the Form 10-K for additional information.

The following table outlines the credit arrangements by company as of March 31, 2011:

			Executable Term-Loans		Expires			Expires Within One Year[(a)]	
Company	**Total**	**Unused**	**One Year**	**Two Years**	**2011**	**2012**	**2013**	**Term Out**	**No Term Out**
					(in millions)				
Southern Company	$ 950	$ 950	$ -	$ -	$ -	$ 950	$ -	$ -	$ -
Alabama Power	1,271	1,271	372	-	506	765	-	372	134
Georgia Power	1,715	1,703	220	40	595	1,120	-	260	335
Gulf Power	240	240	210	-	240	-	-	210	30
Mississippi Power	186	186	90	41	161	25	-	131	55
Southern Power	400	400	-	-	-	400	-	-	-
Other	60	60	60	-	60	-	-	60	-
Total	$4,822	$4,810	$ 952	$81	$1,562	$3,260	$ -	$1,033	$ 554

(a) Reflects facilities expiring on or before March 31, 2012.

(F) RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees. The qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan are expected for the year ending December 31, 2011. Southern 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, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions.

See Note 2 to the financial statements of Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power in Item 8 of the Form 10-K for additional information.

Components of the net periodic benefit costs for the three months ended March 31, 2011 and 2010 were as follows:

Pension Plans	**Southern Company**	**Alabama Power**	**Georgia Power**	**Gulf Power**	**Mississippi Power**
Three Months Ended March 31, 2011			*(in millions)*		
Service cost	$ 46	$ 11	$ 14	$ 2	$ 2
Interest cost	98	24	36	4	4
Expected return on plan assets	(152)	(43)	(59)	(7)	(6)
Net amortization	13	3	5	1	1
Net cost (income)	$ 5	$ (5)	$ (4)	$ -	$ 1
Three Months Ended March 31, 2010					
Service cost	$ 43	$ 10	$ 14	$ 2	$ 2
Interest cost	98	24	36	4	4
Expected return on plan assets	(138)	(42)	(55)	(6)	(5)
Net amortization	11	3	4	1	1
Net cost (income)	$ 14	$ (5)	$ (1)	$ 1	$ 2

Postretirement Benefits	**Southern Company**	**Alabama Power**	**Georgia Power**	**Gulf Power**	**Mississippi Power**
Three Months Ended March 31, 2011			*(in millions)*		
Service cost	$ 5	$ 1	$ 2	$ -	$ -
Interest cost	23	6	10	1	1
Expected return on plan assets	(16)	(6)	(8)	-	-
Net amortization	5	2	3	-	-
Net cost (income)	$ 17	$ 3	$ 7	$ 1	$ 1
Three Months Ended March 31, 2010					
Service cost	$ 6	$ 2	$ 2	$ -	$ -
Interest cost	25	6	11	1	1
Expected return on plan assets	(16)	(6)	(8)	-	-
Net amortization	5	2	3	-	-
Net cost (income)	$ 20	$ 4	$ 8	$ 1	$ 1

(G) EFFECTIVE TAX RATE AND UNRECOGNIZED TAX BENEFITS

Effective Tax Rate

Southern Company's effective tax rate was 34.6% for the three months ended March 31, 2011, as compared to 31.6% for the corresponding period in 2010. Southern Company's effective tax rate is lower than the statutory rate primarily due to its employee stock dividend deduction and AFUDC equity, which is not taxable. See Note 5 to the financial statements of each registrant in Item 8 of the Form 10-K for information on the effective income tax rate. Southern Company's effective tax rate increased primarily due to no production activities deduction and no Georgia state income tax credits for activity through Georgia ports available to Southern Company for the three months ended March 31, 2011, as compared to the production activities deduction and additional Georgia state income tax credits recognized as of March 31, 2010. Additionally, Georgia Power's effective tax rate increased for the three months ended March 31, 2011 as compared to March 31, 2010 from 27.8% to 34.6% primarily due to the impact of Georgia state income tax credits discussed above and a decrease in AFUDC equity, which is not taxable, in the first quarter 2011.

Unrecognized Tax Benefits

Changes during 2011 for unrecognized tax benefits were as follows:

	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
	(in millions)					
Unrecognized tax benefits as of December 31, 2010	$296	$43	$237	$4	$4	$2
Tax positions from current periods	8	2	5	-	1	-
Tax positions from prior periods	-	-	-	-	-	-
Reductions due to expired statute of limitations	-	-	-	-	-	-
Balance as of March 31, 2011	$304	$45	$242	$4	$5	$2

The tax positions from current periods relate primarily to the tax accounting method change for repairs and other miscellaneous uncertain tax positions.

The impact on the effective tax rate, if recognized, is as follows:

	As of March 31, 2011			As of December 31, 2010
	Georgia Power	**Other Registrants**	**Southern Company**	**Southern Company**
	(in millions)			
Tax positions impacting the effective tax rate	**$205**	**$11**	**$221**	$217
Tax positions not impacting the effective tax rate	**37**	**45**	**83**	79
Balance of unrecognized tax benefits	**$242**	**$ 56**	**$304**	$296

The tax positions impacting the effective tax rate primarily relate to Georgia state tax credit litigation at Georgia Power and the production activities deduction tax position. However, if Georgia Power is successful in its claim against the Georgia DOR, a significant portion of the tax benefit is expected to be deferred and returned to retail customers and therefore no material impact to net income is expected. 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 (B) under "Income Tax Matters – Georgia State Income Tax Credits" herein for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	Georgia Power	Other Registrants	Southern Company
		(in millions)	
Interest accrued as of December 31, 2010	$27	$2	$29
Interest reclassified due to settlements	-	-	-
Interest accrued during the period	2	1	3
Balance as of March 31, 2011	$29	$3	$32

All of the registrants classify interest on tax uncertainties as interest expense. The net amount of interest accrued during 2011 was primarily associated with the Georgia state tax credit litigation.

None of the registrants accrued any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of Southern Company's and Georgia Power's unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the Georgia state tax credit litigation would substantially reduce the balances. 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.

Tax Method of Accounting for Repairs

Southern Company submitted a change in the tax accounting method for repair costs associated with its subsidiaries' generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $141 million for Alabama Power, $133 million for Georgia Power, $8 million for Gulf Power, $5 million for Mississippi Power, $6 million for Southern Power, and $297 million for Southern Company on a consolidated basis. 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. The ultimate outcome of this matter cannot be determined at this time.

(H) DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each 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 traditional operating companies and Southern Power enter 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 traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel-hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts which is expected to continue to mitigate price volatility. Southern Power has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

To mitigate residual risks relative to movements in electricity prices, the electric utilities may enter into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the electric utilities may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

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

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' 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 respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges, which are mainly used to hedge anticipated purchases and sales, and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At March 31, 2011, the net volume of energy-related derivative contracts for power and natural gas positions for the registrants, together with the longest hedge date over which the respective entity 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:

	Power			**Gas**		
	Net Sold MWHs	**Longest Hedge Date**	**Longest Non-Hedge Date**	**Net Purchased mmBtu**	**Longest Hedge Date**	**Longest Non-Hedge Date**
	(in millions)			*(in millions)*		
Southern Company	0.8	2011	2011	154	2015	2015
Alabama Power	-	2011	2011	31	2015	-
Georgia Power	-	2011	2011	65	2015	-
Gulf Power	-	2011	2011	20	2015	-
Mississippi Power	-	2011	2011	24	2015	-
Southern Power	0.8	2011	2011	14	2012	2015

In addition to the volumes discussed in the above table, the traditional operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 4 million mmbtu for Southern Company, 4 million mmbtu for Georgia Power, and was immaterial for the other registrants.

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

Interest Rate Derivatives

Southern Company and certain subsidiaries also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. 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 with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset with any difference representing ineffectiveness.

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

	Notional Amount	Interest Rate Received	Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) March 31, 2011
	(in millions)				*(in millions)*
Cash flow hedges of existing debt					
Southern Company	$300	3-month LIBOR + 0.40% spread	1.24%*	October 2011	$(1)
Fair value hedges of existing debt					
Southern Company	350	4.15%	3-month LIBOR + 1.96%* spread	May 2014	9
Total	$650				$8

* Weighted Average

The following table reflects the estimated pre-tax gains (losses) that will be reclassified from OCI to interest expense for the next 12-month period ending March 31, 2012, together with the longest date that total deferred gains and losses are expected to be amortized into earnings.

Registrant	Estimated Gain (Loss) to be Reclassified for the 12 Months Ending March 31, 2012	Total Deferred Gains (Losses) Amortized Through
	(in millions)	
Southern Company	$(16)	2037
Alabama Power	1	2035
Georgia Power	(3)	2037
Gulf Power	(1)	2020
Southern Power	(12)	2016

Foreign Currency Derivatives

Southern Company and certain subsidiaries may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge 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. Any ineffectiveness is recorded directly to earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

At March 31, 2011, the following foreign currency derivatives were outstanding:

	Notional Amount	Forward Rate	Hedge Maturity Date	Fair Value Gain (Loss) March 31, 2011
	(in millions)			*(in millions)*
Cash flow hedges of forecasted transactions				
Southern Company	YEN10	85.23 Yen per Dollar*	May 2011	$-
Fair value hedges of firm commitments				
Mississippi Power	EUR38.9	1.253 Dollars per Euro*	Various through July 2012	6
Total				$6

* Weighted Average

Derivative Financial Statement Presentation and Amounts

At March 31, 2011, the fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected in the balance sheets as follows:

Asset Derivatives at March 31, 2011

	Fair Value					
Derivative Category and Balance Sheet Location	**Southern Company**	**Alabama Power**	**Georgia Power**	**Gulf Power**	**Mississippi Power**	**Southern Power**
	(in millions)					
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Other current assets	$ 4	$1	$ -	$2	$1	
Other deferred charges and assets	6	1	2	1	2	
Total derivatives designated as hedging instruments for regulatory purposes	$10	$2	$2	$3	$3	N/A
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:						
Other current assets	$ 6	$ -	$ -	$-	$ -	$ -
Other deferred charges and assets	3	-	-	-	-	-
Foreign currency derivatives:						
Other current assets	5	-	-	-	5	-
Other deferred charges and assets	1	-	-	-	1	-
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$15	$ -	$ -	$ -	$6	$ -
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
Other current assets*	$ 3	$ -	$ -	$-	$ -	$ -
Assets from risk management activities	-	-	-	-	-	3
Other deferred charges and assets	1	-	-	-	-	1
Total derivatives not designated as hedging instruments	$ 4	$ -	$ -	$ -	$ -	$4
Total asset derivatives	$29	$2	$2	$3	$9	$4

*Southern Company includes “Assets from risk management activities” in “Other current assets” where applicable.

Liability Derivatives at March 31, 2011

Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
	Fair Value					
	(in millions)					
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Liabilities from risk management activities	$126	$24	$70	$ 7	$25	
Other deferred credits and liabilities	40	5	16	4	15	
Total derivatives designated as hedging instruments for regulatory purposes	$166	$29	$86	$11	$40	N/A
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:						
Liabilities from risk management activities	$ 1	$ -	$ -	$ -	$ -	$ -
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
Liabilities from risk management activities	$ 6	$ -	$ -	$ -	$ -	$6
Total liability derivatives	$173	$29	$86	$11	$40	$6

All derivative instruments are measured at fair value. See Note (C) herein for additional information.

At March 31, 2011, 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 sheet was as follows:

Regulatory Hedge Unrealized Gain (Loss) Recognized on the Balance Sheet

Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
	(in millions)				
Energy-related derivatives:					
Other regulatory assets, current	$(126)	$(24)	$ (70)	$(7)	$(25)
Other regulatory assets, deferred	(40)	(5)	(16)	(4)	(15)
Other regulatory liabilities, current	4	-	-	2	1
Other current liabilities*	-	1	-	-	-
Other regulatory liabilities, deferred	6	1	-	1	2
Other deferred credits and liabilities**	-	-	2	-	-
Total energy-related derivative gains (losses)	$(156)	$(27)	$(84)	$(8)	$(37)

* Alabama Power includes "Other regulatory liabilities, current" in "Other current liabilities."
** Georgia Power includes "Other regulatory liabilities, deferred" in "Other deferred credits and liabilities."

For the three months ended March 31, 2011 and March 31, 2010, the pre-tax gains from interest rate derivatives designated as fair value hedging instruments on Southern Company's statements of income were immaterial.

For the three months ended March 31, 2011, the pre-tax gains from foreign currency derivatives designated as fair value hedging instruments on Southern Company's and Mississippi Power's statements of income were $3 million. This amount was offset with changes in the fair value of the purchase commitment related to equipment purchases; therefore, there is no impact on Southern Company's or Mississippi Power's statements of income.

For the three months ended March 31, 2011 and March 31, 2010, the pre-tax effect of derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)		Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)		
			Statements of Income Location	Amount	
	2011	2010		**2011**	2010
	(in millions)			*(in millions)*	
Southern Company					
Energy-related derivatives	**$1**	$5	Fuel	**$-**	$-
Interest rate derivatives	**4**	(3)	Interest expense, net of amounts capitalized	**(5)**	(9)
Total	**$5**	$2		**$(5)**	$(9)
Alabama Power					
Interest rate derivatives	**$4**	$-	Interest expense, net of amounts capitalized	**$-**	$(2)
Georgia Power					
Interest rate derivatives	**$-**	$-	Interest expense, net of amounts capitalized	**$(1)**	$(5)
Gulf Power					
Interest rate derivatives	**$-**	$(2)	Interest expense, net of amounts capitalized	**$-**	$-
Southern Power					
Energy-related derivatives	**$1**	$4	Fuel	**$-**	$-
Interest rate derivatives	**-**	-	Interest expense, net of amounts capitalized	**(3)**	(3)
Total	**$1**	$4		**$(3)**	$(3)

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

For the three months ended March 31, 2011 and March 31, 2010, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income were immaterial for Southern Company and Southern Power.

Contingent Features

The registrants do 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 Southern Company subsidiaries. At March 31, 2011, the fair value of derivative liabilities with contingent features, by registrant, was as follows:

	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Derivative liabilities	$32	$5	$20	$-	$4	$3

At March 31, 2011, the registrants had no collateral posted with their 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 $32 million for each registrant.

Currently, each of the registrants has investment grade credit ratings from the major rating agencies with respect to debt, preferred securities, preferred stock, and/or preference stock. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. For the traditional operating companies and Southern Power, included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participants has a credit rating change to below investment grade.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

(I) SEGMENT AND RELATED INFORMATION

Southern Company's reportable business segments are the sale of electricity in the Southeast by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $83 million and $102 million for the three months ended March 31, 2011 and March 31, 2010, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications, and leveraged lease projects. All other intersegment revenues are not material. Financial data for business segments and products and services was as follows:

	Electric Utilities						
	Traditional Operating Companies	**Southern Power**	**Eliminations**	**Total**	**All Other**	**Eliminations**	**Consolidated**
				(*in millions*)			
Three Months Ended March 31, 2011:							
Operating revenues	$3,810	$ 282	$(98)	$3,994	$38	$(20)	$4,012
Segment net income *	385	38	-	423	1	(2)	422
Total assets at March 31, 2011	$51,138	$3,461	$(74)	$54,525	$1,059	$(565)	$55,019
Three Months Ended March 31, 2010:							
Operating revenues	$4,005	$ 256	$(125)	$ 4,136	$ 41	$ (20)	$ 4,157
Segment net income (loss)*	481	15	-	496	-	(1)	495
Total assets at December 31, 2010	$51,144	$3,438	$(128)	$54,454	$1,178	$(600)	$55,032

*After dividends on preferred and preference stock of subsidiaries

Products and Services

	Electric Utilities' Revenues			
Period	**Retail**	**Wholesale**	**Other**	**Total**
		(*in millions*)		
Three Months Ended March 31, 2011	$3,396	$449	$149	$3,994
Three Months Ended March 31, 2010	$3,459	$542	$135	$4,136

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

See the Notes to the Condensed Financial Statements herein for information regarding certain legal and administrative proceedings in which the registrants are involved.

Item 1A. Risk Factors.

See RISK FACTORS in Item 1A of the Form 10-K for a discussion of the risk factors of the registrants. There have been no material changes to these risk factors from those previously disclosed in the Form 10-K.

Item 6. Exhibits.

(3) Articles of Incorporation and By-Laws

Alabama Power

(b)1 - By-laws of Alabama Power as amended effective April 22, 2011 and presently in effect. (Designated in Form 8-K dated April 22, 2011, File No. 1-3164 as Exhibit 3.1.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

Alabama Power

(b)1 - Forty-Fifth Supplemental Indenture to Senior Note Indenture dated as of March 10, 2011, providing for the issuance of the Series 2011A 5.50% Senior Notes due March 15, 2041. (Designated in Form 8-K dated March 3, 2011, File No. 1-3164, as Exhibit 4.2.)

Georgia Power

(c)1 - Forty-Fifth Supplemental Indenture to Senior Note Indenture dated as of April 19, 2011, providing for the issuance of the Series 2011B 3.00% Senior Notes due April 15, 2016. (Designated in Form 8-K dated April 12, 2011, File No. 1-6468, as Exhibit 4.2.)

(10) Material Contracts

Southern Company

(a)1 - Termination of Amended and Restated Change in Control Agreement effective February 22, 2011 between Southern Company, SCS and G. Edison Holland, Jr.

(a)2 - Amended Deferred Compensation Agreement, effective December 31, 2008 between Southern Company, SCS, Georgia Power, Gulf Power and G. Edison Holland, Jr.

(a)3 - Form of Stock Option Award Agreement for Executive Officers of Southern Company, under the Southern Company Omnibus Incentive Compensation Plan.

(a)4 - Base Salaries of Named Executive Officers.

(a)5 - Summary of Non-Employee Director Compensation Arrangements.

Georgia Power

(c)1 - Retention Agreement between Georgia Power and Michael A. Brown, effective January 1, 2011.

(24) Power of Attorney and Resolutions

Southern Company

(a)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2010, File No. 1-3526 as Exhibit 24(a) and incorporated herein by reference.)

Alabama Power

(b)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2010, File No. 1-3164 as Exhibit 24(b) and incorporated herein by reference.)

Georgia Power

(c)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2010, File No. 1-6468 as Exhibit 24(c) and incorporated herein by reference.)

Gulf Power

(d)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2010, File No. 001-31737 as Exhibit 24(d)1 and incorporated herein by reference.)

(d)2 - Power of Attorney Mark A. Crosswhite. (Designated in the Form 10-K for the year ended December 31, 2010, File No. 001-31737 as Exhibit 24(d)2 and incorporated herein by reference.)

Mississippi Power

(e)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2010, File No. 001-11229 as Exhibit 24(e) and incorporated herein by reference.)

Southern Power

(f)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2010, File No. 333-98553 as Exhibit 24(f) and incorporated herein by reference.)

(31) Section 302 Certifications

Southern Company

(a)1 - Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(a)2 - Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

(b)1 - Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(b)2 - Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Georgia Power

(c)1 - Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(c)2 - Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Gulf Power

(d)1 - Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(d)2 - Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

(e)1 - Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(e)2 - Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Power

(f)1 - Certificate of Southern Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(f)2 - Certificate of Southern Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company

(a) - Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Alabama Power

(b) - Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Georgia Power

(c) - Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Gulf Power

(d) - Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

(e) - Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Power

(f)	- Certificate of Southern Power’s Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(101) XBRL – Related Documents

Southern Company

INS	XBRL Instance Document
SCH	XBRL Taxonomy Extension Schema Document
CAL	XBRL Taxonomy Calculation Linkbase Document
DEF	XBRL Definition Linkbase Document
LAB	XBRL Taxonomy Label Linkbase Document
PRE	XBRL Taxonomy Presentation Linkbase Document

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By *Thomas A. Fanning*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *Art P. Beattie*
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

By *<u>/s/ Melissa K. Caen</u>*
(Melissa K. Caen, Attorney-in-fact)

Date: May 6, 2011

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By *Charles D. McCrary*
President and Chief Executive Officer
(Principal Executive Officer)

By *Philip C. Raymond*
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 6, 2011

GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By *W. Paul Bowers*
President and Chief Executive Officer
(Principal Executive Officer)

By *Ronnie R. Labrato*
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 6, 2011

GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By *Mark A. Crosswhite*
President and Chief Executive Officer
(Principal Executive Officer)

By *Richard S. Teel*
Vice President and Chief Financial Officer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 6, 2011

MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By *Edward Day, VI*
President and Chief Executive Officer
(Principal Executive Officer)

By *Moses H. Feagin*
Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 6, 2011

SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN POWER COMPANY

By *Oscar C. Harper, IV*
President and Chief Executive Officer
(Principal Executive Officer)

By *Michael W. Southern*
Senior Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 6, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(X) ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2010
OR
( ) TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
333-98553	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

Securities registered pursuant to Section 12(b) of the Act:[1]

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is listed on the New York Stock Exchange.

Title of each class		Registrant
Common Stock, $5 par value		**The Southern Company**
Class A preferred, cumulative, $25 stated capital		**Alabama Power Company**
5.20% Series	5.83% Series	
5.30% Series		
Senior Notes		
5 7/8% Series GG	5.875% Series II	
5.875% Series 2007B	6.375% Series JJ	
Class A Preferred Stock, non-cumulative, Par value $25 per share		**Georgia Power Company**
6 1/8% Series		
Senior Notes		
6.375% Series 2007D		
8.20% Series 2008C		
Long-term debt payable to affiliated trusts, $25 liquidation amount		
5 7/8% Trust Preferred Securities[2]		
Senior Notes		**Gulf Power Company**
5.25% Series H		
Senior Notes		**Mississippi Power Company**
5 5/8% Series E		
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value		
5.25% Series		

1 As of December 31, 2010.

2 Issued by Georgia Power Capital Trust VII and guaranteed by Georgia Power Company.

Securities registered pursuant to Section 12(g) of the Act:[3]

Title of each class			**Registrant**
Preferred stock, cumulative, $100 par value			**Alabama Power Company**
4.20% Series	4.60% Series	4.72% Series	
4.52% Series	4.64% Series	4.92% Series	

Preferred stock, cumulative, $100 par value			**Mississippi Power Company**
4.40% Series	4.60% Series		
4.72% Series			

3 As of December 31, 2010.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
The Southern Company	x	
Alabama Power Company	x	
Georgia Power Company	x	
Gulf Power Company		x
Mississippi Power Company		x
Southern Power Company		x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes _ No X (Response applicable to all registrants.)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes X No _

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes _X_ No____(Response applicable only to The Southern Company at this time.)

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. (X)

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Registrant	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
The Southern Company	X			
Alabama Power Company			X	
Georgia Power Company			X	
Gulf Power Company			X	
Mississippi Power Company			X	
Southern Power Company			X	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes _ No X (Response applicable to all registrants.)

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2010: $27.6 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at January 31, 2011
The Southern Company	Par Value $5 Per Share	845,614,704
Alabama Power Company	Par Value $40 Per Share	30,537,500
Georgia Power Company	Without Par Value	9,261,500
Gulf Power Company	Without Par Value	4,142,717
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2011 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statements on Schedule 14C of Alabama Power Company, Georgia Power Company, and Mississippi Power Company relating to each of their respective 2011 Annual Meetings of Shareholders are incorporated by reference into PART III.

Southern Power Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instructions I(2)(b), (c), and (d) of Form 10-K.

This combined Form 10-K is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

Table of Contents

DEFINITIONS

When used in Items 1 through 5 and Items 9A through 15, the following terms will have the meanings indicated.

Term	**Meaning**
2010 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2011 through 2013
AFUDC	Allowance for Funds Used During Construction
Alabama Power	Alabama Power Company
AMEA	Alabama Municipal Electric Authority
Clean Air Act	Clean Air Act Amendments of 1990
Code	Internal Revenue Code of 1986, as amended
CPCN	Certificate of Public Convenience and Necessity
Dalton	Dalton Utilities
DOE	United States Department of Energy
Duke Energy	Duke Energy Corporation
ECCR	Georgia Power Environmental Compliance Cost Recovery
Energy Act of 1992	Energy Policy Act of 1992
Energy Act of 2005	Energy Policy Act of 2005
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FMPA	Florida Municipal Power Agency
FP&L	Florida Power & Light Company
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
Hampton	City of Hampton, Georgia
IBEW	International Brotherhood of Electrical Workers
IGCC	Integrated Coal Gasification Combined Cycle
IIC	Intercompany Interchange Contract
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
Kemper IGCC	IGCC facility under construction in Kemper County, Mississippi
KUA	Kissimmee Utility Authority
MEAG Power	Municipal Electric Authority of Georgia
Mirant	Mirant Corporation
Mississippi Power	Mississippi Power Company
Moody's	Moody's Investors Service
NRC	Nuclear Regulatory Commission
OPC	Oglethorpe Power Corporation
OUC	Orlando Utilities Commission
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power are subject to joint commitment and dispatch in order to serve their combined load obligations
PowerSouth	PowerSouth Energy Cooperative (formerly, Alabama Electric Cooperative, Inc.)
PPA	Power Purchase Agreement
Progress Energy Carolinas	Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.

DEFINITIONS
(continued)

Term	Meaning
Progress Energy Florida	Florida Power Corporation, d/b/a Progress Energy Florida, Inc.
PSC	Public Service Commission
registrants	The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company
RFP	Request for Proposal
RUS	Rural Utilities Service (formerly Rural Electrification Administration)
S&P	Standard & Poor's, a division of The McGraw-Hill Companies
SCS	Southern Company Services, Inc. (the system service company)
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company
Southern Renewable Energy	Southern Renewable Energy, Inc.
Stone & Webster	Stone & Webster, Inc.
traditional operating companies	Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company
TVA	Tennessee Valley Authority
Westinghouse	Westinghouse Electric Company LLC

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the wholesale business, retail sales, customer growth, economic recovery, fuel cost recovery and other rate actions, environmental regulations and expenditures, future earnings, dividend payout ratios, access to sources of capital, projections for the qualified pension, postretirement benefit, and nuclear decommissioning trust fund contributions, financing activities, start and completion of construction projects, plans and estimated costs for new generation resources, 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 Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and IRS audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company’s subsidiaries operate;
- 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 Southern Company’s employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to the Plant Vogtle expansion, including Georgia PSC and NRC approvals and potential DOE loan guarantees;
- regulatory approvals and actions related to the Kemper IGCC, including Mississippi PSC approvals and potential DOE loan guarantees;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- 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 Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries 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 Southern 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 Southern Company’s and its subsidiaries’ credit ratings;
- the ability of Southern Company and its subsidiaries 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 Southern 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 filed by the registrants from time to time with the SEC.

The registrants expressly disclaim any obligation to update any forward-looking statements.

[This page intentionally left blank]

PART I

Item 1. BUSINESS

Southern Company was incorporated under the laws of Delaware on November 9, 1945. Southern Company is domesticated under the laws of Georgia and is qualified to do business as a foreign corporation under the laws of Alabama. Southern Company owns all of the outstanding common stock of Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, each of which is an operating public utility company. The traditional operating companies supply electric service in the states of Alabama, Georgia, Florida, and Mississippi. More particular information relating to each of the traditional operating companies is as follows:

Alabama Power is a corporation organized under the laws of the State of Alabama on November 10, 1927, by the consolidation of a predecessor Alabama Power Company, Gulf Electric Company, and Houston Power Company. The predecessor Alabama Power Company had been in continuous existence since its incorporation in 1906.

Georgia Power was incorporated under the laws of the State of Georgia on June 26, 1930 and was admitted to do business in Alabama on September 15, 1948.

Gulf Power is a Florida corporation that has had a continuous existence since it was originally organized under the laws of the State of Maine on November 2, 1925. Gulf Power was admitted to do business in Florida on January 15, 1926, in Mississippi on October 25, 1976, and in Georgia on November 20, 1984. Gulf Power became a Florida corporation after being domesticated under the laws of the State of Florida on November 2, 2005.

Mississippi Power was incorporated under the laws of the State of Mississippi on July 12, 1972, was admitted to do business in Alabama on November 28, 1972, and effective December 21, 1972, by the merger into it of the predecessor Mississippi Power Company, succeeded to the business and properties of the latter company. The predecessor Mississippi Power Company was incorporated under the laws of the State of Maine on November 24, 1924 and was admitted to do business in Mississippi on December 23, 1924 and in Alabama on December 7, 1962.

In addition, Southern Company owns all of the common stock of Southern Power, which is also an operating public utility company. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market. Southern Power is a corporation organized under the laws of Delaware on January 8, 2001 and was admitted to do business in the States of Alabama, Florida, and Georgia on January 10, 2001, in the State of Mississippi on January 30, 2001, and in the State of North Carolina on February 19, 2007.

Southern Company also owns all of the outstanding common stock or membership interests of SouthernLINC Wireless, Southern Nuclear, SCS, Southern Holdings, Southern Renewable Energy, and other direct and indirect subsidiaries. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets these services to the public and also provides wholesale fiber optic solutions to telecommunication providers in the Southeast. Southern Nuclear operates and provides services to Alabama Power's and Georgia Power's nuclear plants and is currently developing new nuclear generation at Plant Vogtle. SCS is the system service company providing, at cost, specialized services to Southern Company and its subsidiary companies. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in leveraged leases. Southern Renewable Energy was formed in January 2010 to construct, acquire, own, and manage renewable generation assets.

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,019,680 kilowatts at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO's capacity and energy. Alabama Power acts as SEGCO's agent in the operation of SEGCO's units and furnishes coal to SEGCO as fuel for its units. SEGCO also owns one 230,000 volt transmission line extending from Plant Gaston to the Georgia state line at which point connection is made with the Georgia Power transmission line system.

Southern Company's segment information is included in Note 12 to the financial statements of Southern Company in Item 8 herein.

The registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports are made available on Southern Company's website, free of charge, as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Southern Company's internet address is www.southerncompany.com.

The Southern Company System

Traditional Operating Companies

The traditional operating companies own generation, transmission, and distribution facilities. See PROPERTIES in Item 2 herein for additional information on the traditional operating companies' generating facilities. Each company's transmission facilities are connected to the respective company's own generating plants and other sources of power (including certain generating plants owned by Southern Power) and are interconnected with the transmission facilities of the other traditional operating companies and SEGCO. For information on the State of Georgia's integrated transmission system, see "Territory Served by the Traditional Operating Companies and Southern Power" herein.

Agreements in effect with principal neighboring utility systems provide for capacity and energy transactions that may be entered into from time to time for reasons related to reliability or economics. Additionally, the traditional operating companies have entered into voluntary reliability agreements with the subsidiaries of Entergy Corporation, Florida Electric Power Coordinating Group, and TVA and with Progress Energy Carolinas, Duke Energy, South Carolina Electric & Gas Company, and Virginia Electric and Power Company, each of which provides for the establishment and periodic review of principles and procedures for planning and operation of generation and transmission facilities, maintenance schedules, load retention programs, emergency operations, and other matters affecting the reliability of bulk power supply. The traditional operating companies have joined with other utilities in the Southeast (including some of those referred to above) to form the SERC to augment further the reliability and adequacy of bulk power supply. Through the SERC, the traditional operating companies are represented on the National Electric Reliability Council.

The utility assets of the traditional operating companies and certain utility assets of Southern Power are operated as a single integrated electric system, or power pool, pursuant to the IIC. Activities under the IIC are administered by SCS, which acts as agent for the traditional operating companies and Southern Power. The fundamental purpose of the power pool is to provide for the coordinated operation of the electric facilities in an effort to achieve the maximum possible economies consistent with the highest practicable reliability of service. Subject to service requirements and other operating limitations, system resources are committed and controlled through the application of centralized economic dispatch. Under the IIC, each traditional operating company and Southern Power retains its lowest cost energy resources for the benefit of its own customers and delivers any excess energy to the power pool for use in serving customers of other traditional operating companies or Southern Power or for sale by the power pool to third parties. The IIC provides for the recovery of specified costs associated with the affiliated operations thereunder, as well as the proportionate sharing of costs and revenues resulting from power pool transactions with third parties.

Southern Company, each traditional operating company, Southern Power, Southern Nuclear, SEGCO, and other subsidiaries have contracted with SCS to furnish, at direct or allocated cost and upon request, the following services: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Southern Power and SouthernLINC Wireless have also secured from the traditional operating companies certain services which are furnished at cost and, in the case of Southern Power, which are subject to FERC regulations, in compliance with such regulations.

Alabama Power and Georgia Power each have a contract with Southern Nuclear to operate Plant Farley and Plants Hatch and Vogtle, respectively. In addition, Georgia Power has a contract with Southern Nuclear to develop, license, construct, and operate additional generating units at Plant Vogtle. See "Regulation – Nuclear Regulation" herein for additional information.

Southern Power

Southern Power is an electric wholesale generation subsidiary with market-based rate authority from the FERC. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based prices in the wholesale market. Southern Power's business activities are not subject to traditional state regulation like the traditional operating companies but are subject to regulation by the FERC. Southern Power has attempted to insulate itself from significant fuel supply, fuel transportation, and electric transmission risks by making such risks the responsibility of the counterparties to its PPAs. However, Southern Power's future earnings will depend on the parameters of the wholesale market, federal regulation, and the efficient operation of its wholesale generating assets. For additional information on Southern Power's business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Business Activities" of Southern Power in Item 7 herein.

In 2008, Southern Power completed construction on Plant Franklin Unit 3 which added 659 megawatts to the Southern Company system generating capacity. Southern Power is constructing a 720-megawatt electric generating plant in Cleveland County, North Carolina. This new plant is expected to go into commercial operation in 2012. The total estimated construction cost is expected to be between $350 million and $400 million.

In October 2009, Southern Power acquired all of the outstanding membership interests of Nacogdoches Power LLC from American Renewables LLC, the original developer of a biomass project in Sacul, Texas. Southern Power continues to construct the Nacogdoches biomass generating plant with an estimated capacity of 100 megawatts. The generating plant will be fueled from wood waste and is expected to begin commercial operation in 2012. The total estimated cost of the project is expected to be between $475 million and $500 million.

In December 2009, Southern Power acquired all of the outstanding membership interests of West Georgia Generating Company, LLC (West Georgia) from Broadway Gen Funding, LLC, an affiliate of LS Power. West Georgia was merged into Southern Power as of the acquisition date and Southern Power now owns a dual-fueled generating plant near Thomaston, Georgia with nameplate capacity of approximately 669 megawatts. The plant consists of four combustion turbine natural gas generating units with oil back-up.

As of December 31, 2010, Southern Power had 7,880 megawatts of nameplate capacity in commercial operation.

Other Businesses

Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in leveraged leases.

SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets its services to non-affiliates within the Southeast. SouthernLINC Wireless delivers multiple wireless communication options including push to talk, cellular service, text messaging, wireless internet access, and wireless data. Its system covers approximately 127,000 square miles in the Southeast. SouthernLINC Wireless also provides wholesale fiber optic solutions to telecommunication providers in the Southeast under the name Southern Telecom.

On January 25, 2010, Southern Renewable Energy was formed to construct, acquire, own, and manage renewable generation assets. On March 12, 2010, Southern Renewable Energy and Turner Renewable Energy acquired from First Solar, Inc. the Cimarron project, a 30-megawatt solar photovoltaic plant near Cimarron, New Mexico. On November 25, 2010, the Cimarron plant began commercial operation.

These efforts to invest in and develop new business opportunities offer potential returns exceeding those of rate-regulated operations. However, these activities also involve a higher degree of risk.

Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2011 through 2013, see Note 7 to the financial statements of Southern Company and each traditional operating company under "Construction Program" and Note 7 to the financial statements of Southern Power under "Expansion Program" in Item 8 herein. Base level estimated construction costs in 2011 are expected to be apportioned approximately as follows: (in millions)

	Southern Company System *	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
New Generation	$2,171	$ -	$934	$ -	$665	$572
Environmental **	341	47	73	176	45	-
Transmission & Distribution Growth	530	123	349	39	20	-
Maintenance (Generation, Transmission & Distribution)	1,270	532	489	154	79	-
Nuclear fuel	299	129	170	-	-	-
General plant	278	86	95	12	9	27
Total ***	$4,889	$917	$2,110	$381	$818	$599

* These amounts include the traditional operating companies and Southern Power (as detailed in the table above) as well as the amounts for the other subsidiaries. See "Other Businesses" herein for additional information.

** These amounts reflect estimated capital expenditures in 2011 to comply with existing statutes and regulations. In addition, each of Southern Company and the traditional operating companies has estimated of a range of potential incremental investments to comply with proposed environmental regulations. These additional estimated amounts for 2011 are: from $74 million to $289 million for the Southern Company system; up to $48 million for Alabama Power; from $69 million to $289 million for Georgia Power; and up to $17 million for Gulf Power. Mississippi Power and Southern Power have no anticipated incremental investments to comply with anticipated new environmental regulation in 2011.

*** The estimated 2011 total for Southern Power includes cash payments for long-term service agreements.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirement and replacement decisions, to meet new regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

See "Regulation – Environmental Statutes and Regulations" herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information concerning Alabama Power's, Georgia Power's, and Southern Power's joint ownership of certain generating units and related facilities with certain non-affiliated utilities.

Financing Programs

See each of the registrant's MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY in Item 7 herein and Note 6 to the financial statements of each registrant in Item 8 herein for information concerning financing programs.

Fuel Supply

The traditional operating companies' and SEGCO's supply of electricity is derived mainly from coal. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Fuel and Purchased Power Expenses" of Southern Company and each traditional operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net kilowatt-hour generated for the years 2008 through 2010.

The traditional operating companies have agreements in place from which they expect to receive approximately 97.5% of their coal burn requirements in 2011. These agreements have terms ranging between one and eight years. In 2010, the weighted average sulfur content of all coal burned by the traditional operating companies was 0.78% sulfur. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional operating companies to remain within limits set by Phase I of the Clean Air Interstate Rule under the Clean Air Act. In 2010, the Southern Company system purchased approximately 35,000 tons of sulfur dioxide allowances, 6,650 tons of annual nitrogen oxide emissions allowances, and 2,100 tons of seasonal nitrogen oxide emission allowances to be used in current and future periods. As additional environmental regulations are proposed that impact the utilization of coal, the traditional operating companies' fuel mix will be monitored to ensure that the traditional operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for emissions control equipment, and potential unit retirements and replacements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each traditional operating company in Item 7 herein for information on the Clean Air Act, water quality, coal combustion byproducts, and global climate issues.

SCS, acting on behalf of the traditional operating companies and Southern Power, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2011, SCS has contracted for 255 billion cubic feet of natural gas supply under agreements with remaining terms up to 10 years. In addition to gas supply, SCS has contracts in place for both firm gas transportation and storage. Management believes that these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units.

Changes in fuel prices to the traditional operating companies are generally reflected in fuel adjustment clauses contained in rate schedules. See "Rate Matters – Rate Structure and Cost Recovery Plans" herein for additional information. Southern Power's PPAs generally provide that the counterparty is responsible for substantially all of the cost of fuel.

Alabama Power and Georgia Power have numerous contracts covering a portion of their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. These contracts have varying expiration dates and most of them are for less than 10 years. Management believes that sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of the Southern Company system's nuclear generating units.

Alabama Power and Georgia Power have contracts with the United States, acting through the DOE, that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in 1998, as required by the contracts, and Alabama Power and Georgia Power are pursuing legal remedies against the government for breach of contract. See Note 3 to the financial statements of Southern Company, Alabama Power, and Georgia Power under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information.

Territory Served by the Traditional Operating Companies and Southern Power

The territory in which the traditional operating companies provide electric service comprises most of the states of Alabama and Georgia together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems which obtain some or all of their power requirements either directly or indirectly from the traditional operating companies. The territory has an area of approximately 120,000 square miles and an estimated population of approximately 13 million. Southern Power sells electricity at market-based prices in the wholesale market to investor-owned utilities, IPPs, municipalities, and electric cooperatives.

Alabama Power is engaged, within the State of Alabama, in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity at retail in over 650 communities (including Anniston, Birmingham, Gadsden, Mobile, Montgomery, and Tuscaloosa), as well as in rural areas, and at wholesale to 15 municipally-owned electric distribution systems, 11 of which are served indirectly through sales to AMEA, and two rural distributing cooperative associations. Alabama Power owns coal reserves near its Plant Gorgas and uses the output of coal from the reserves in its generating plants. Alabama Power also sells, and cooperates with dealers in promoting the sale of, electric appliances.

Georgia Power is engaged in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity within the State of Georgia at retail in over 600 communities (including Athens, Atlanta, Augusta, Columbus, Macon, Rome, and Savannah), as well as in rural areas, and at wholesale currently to OPC, MEAG Power, Dalton, Hampton, and various electric membership corporations.

Gulf Power is engaged, within the northwestern portion of Florida, in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity at retail in 71 communities (including Pensacola, Panama City, and Fort Walton Beach), as well as in rural areas, and at wholesale to a non-affiliated utility and a municipality.

Mississippi Power is engaged in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity within 23 counties in southeastern Mississippi, at retail in 123 communities (including Biloxi, Gulfport, Hattiesburg, Laurel, Meridian, and Pascagoula), as well as in rural areas, and at wholesale to one municipality, six rural electric distribution cooperative associations, and one generating and transmitting cooperative.

For information relating to kilowatt-hour sales by customer classification for the traditional operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS of each traditional operating company in Item 7 herein. Also, for information relating to the sources of revenues for Southern Company, each traditional operating company, and Southern Power, reference is made to Item 7 herein.

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. There are 71 electric cooperative organizations operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama and northwest Florida. PowerSouth owns generating units with approximately 1,776 megawatts of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available.

Alabama Power and Gulf Power have entered into separate agreements with PowerSouth involving interconnection between their respective systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the service areas of Alabama Power and Gulf Power is governed by the Southern Company/PowerSouth Network Transmission Service Agreement. The rates for this service to PowerSouth are on file with the FERC. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller.

Four electric cooperative associations, financed by the RUS, operate within Gulf Power's service area. These cooperatives purchase their full requirements from PowerSouth and SEPA (a federal power marketing agency). A non-affiliated utility also operates within Gulf Power's service area and purchases its full requirements from Gulf Power.

Mississippi Power has an interchange agreement with SMEPA, a generating and transmitting cooperative, pursuant to which various services are provided, including the furnishing of protective capacity by Mississippi Power to

SMEPA. On July 27, 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA will purchase an undivided 17.5% interest in the Kemper IGCC. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. On December 2, 2010, Mississippi Power and SMEPA filed a joint petition with the Mississippi PSC requesting regulatory approval for SMEPA's 17.5% ownership of the Kemper IGCC.

There are also 65 municipally-owned electric distribution systems operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

Forty-eight municipally-owned electric distribution systems and one county-owned system receive their requirements through MEAG Power, which was established by a Georgia state statute in 1975. MEAG Power serves these requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, power purchased from Georgia Power, and purchases from other resources. MEAG Power also has a pseudo scheduling and services agreement with Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and through purchases from Georgia Power and Southern Power through a service agreement. In addition, Georgia Power serves the full requirements of Hampton's electric distribution system under a market-based contract. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Georgia Power has entered into substantially similar agreements with Georgia Transmission Corporation (formerly OPC's transmission division), MEAG Power, and Dalton providing for the establishment of an integrated transmission system to carry the power and energy of all parties. The agreements require an investment by each party in the integrated transmission system in proportion to its respective share of the aggregate system load. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Southern Power has PPAs with some of the traditional operating companies and with other investor-owned utilities, IPPs, municipalities, and electric cooperatives. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 herein for additional information concerning Southern Power's PPAs.

SCS, acting on behalf of the traditional operating companies, also has a contract with SEPA providing for the use of the traditional operating companies' facilities at government expense to deliver to certain cooperatives and municipalities, entitled by federal statute to preference in the purchase of power from SEPA, quantities of power equivalent to the amounts of power allocated to them by SEPA from certain United States government hydroelectric projects.

Pursuant to the 1956 Utility Act, the Mississippi PSC issued "Grandfather Certificates" of public convenience and necessity to Mississippi Power and to six distribution rural cooperatives operating in southeastern Mississippi, then served in whole or in part by Mississippi Power, authorizing them to distribute electricity in certain specified geographically described areas of the state. The six cooperatives serve approximately 325,000 retail customers in a certificated area of approximately 10,300 square miles. In areas included in a "Grandfather Certificate," the utility holding such certificate may, without further certification, extend its lines up to five miles; other extensions within that area by such utility, or by other utilities, may not be made except upon a showing of, and a grant of a certificate of, public convenience and necessity. Areas included in such a certificate which are subsequently annexed to municipalities may continue to be served by the holder of the certificate, irrespective of whether it has a franchise in the annexing municipality. On the other hand, the holder of the municipal franchise may not extend service into such newly annexed area without authorization by the Mississippi PSC.

Competition

The electric utility industry in the United States is continuing to evolve as a result of regulatory and competitive factors. Among the early primary agents of change was the Energy Act of 1992 which allowed IPPs to access a utility's transmission network in order to sell electricity to other utilities.

The competition for retail energy sales among competing suppliers of energy is influenced by various factors, including price, availability, technological advancements, service, and reliability. These factors are, in turn, affected by, among other influences, regulatory, political, and environmental considerations, taxation, and supply.

The retail service rights of all electric suppliers in the State of Georgia are regulated by the Territorial Electric Service Act of 1973. Pursuant to the provisions of this Act, all areas within existing municipal limits were assigned to the primary electric supplier therein. Areas outside of such municipal limits were either to be assigned or to be declared open for customer choice of supplier by action of the Georgia PSC pursuant to standards set forth in this Act. Consistent with such standards, the Georgia PSC has assigned substantially all of the land area in the state to a supplier. Notwithstanding such assignments, this Act provides that any new customer locating outside of 1973 municipal limits and having a connected load of at least 900 kilowatts may exercise a one-time choice for the life of the premises to receive electric service from the supplier of its choice.

Generally, the traditional operating companies have experienced, and expect to continue to experience, competition in their respective retail service territories in varying degrees as the result of self-generation (as described below) by customers and other factors.

Southern Power competes with investor owned utilities, IPPs, and others for wholesale energy sales primarily in the Southeastern United States wholesale market. The needs of this market are driven by the demands of end users in the Southeast and the generation available. Southern Power’s success in wholesale energy sales is influenced by various factors including reliability and availability of Southern Power’s plants, availability of transmission to serve the demand, price, and Southern Power’s ability to contain costs.

Alabama Power currently has cogeneration contracts in effect with 10 industrial customers. Under the terms of these contracts, Alabama Power purchases excess generation of such companies. During 2010, Alabama Power purchased approximately 194 million kilowatt-hours from such companies at a cost of $8.2 million.

Georgia Power currently has contracts in effect with 11 small power producers whereby Georgia Power purchases their excess generation. During 2010, Georgia Power purchased 45 million kilowatt-hours from such companies at a cost of $1.6 million. Georgia Power has PPAs for electricity with two cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2010, Georgia Power purchased 178 million kilowatt-hours at a cost of $27.7 million from these facilities.

Also during 2010, Georgia Power purchased energy from eight customer-owned generating facilities. Seven of the eight customers provide only energy to Georgia Power. These seven customers make no capacity commitment and are not dispatched by Georgia Power. Georgia Power does have a contract with the remaining customer for eight megawatts of dispatchable capacity and energy. During 2010, Georgia Power purchased a total of 49 million kilowatt-hours from the eight customers at a cost of approximately $1.9 million.

Gulf Power currently has agreements in effect with various industrial, commercial, and qualifying facilities pursuant to which Gulf Power purchases “as available” energy from customer-owned generation. During 2010, Gulf Power purchased 111.7 million kilowatt-hours from such companies for approximately $6.3 million.

Mississippi Power currently has a cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2010, Mississippi Power did not purchase any excess generation from this customer.

Seasonality

The demand for electric power generation is affected by seasonal differences in the weather. At the traditional operating companies and Southern Power, the demand for power peaks during the summer months, with market prices reflecting the demand of power and available generating resources at that time. Power demand peaks can also be recorded during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional operating companies, and Southern Power have historically sold less power when weather conditions are milder.

Regulation

State Commissions

The traditional operating companies are subject to the jurisdiction of their respective state PSCs. The PSCs have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Traditional Operating Companies and Southern Power" and "Rate Matters" herein for additional information.

Federal Power Act

The traditional operating companies, Southern Power and its generation subsidiaries, SEGCO, and Southern Renewable Energy's generation subsidiary are all public utilities engaged in wholesale sales of energy in interstate commerce and therefore are subject to the rate, financial, and accounting jurisdiction of the FERC under the Federal Power Act. The FERC must approve certain financings and allows an "at cost standard" for services rendered by system service companies such as SCS. The FERC is also authorized to establish regional reliability organizations which are authorized to enforce reliability standards, to address impediments to the construction of transmission, and to prohibit manipulative energy trading practices.

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. Among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,662,400 kilowatts and 18 existing Georgia Power generating stations having an aggregate installed capacity of 1,087,296 kilowatts.

In July 2005, Alabama Power filed two applications with the FERC for new 50-year licenses for its seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine developments expired in July and August 2007. Since the FERC did not act on any of the new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses under the terms and conditions of the existing licenses, until action is taken on the new license applications. The FERC issued an annual license to the Coosa developments in August 2007, which was automatically renewed in 2008, 2009, and 2010. On March 31, 2010, the FERC issued a new 30-year license for the Lewis Smith and Bankhead developments on the Warrior River. The new license authorizes Alabama Power to continue operating these facilities in a manner consistent with past operations. On April 30, 2010, a stakeholders group filed a request for rehearing of the FERC order issuing the new license. On May 27, 2010, the FERC granted the rehearing request for the limited purpose of allowing the FERC additional time to consider the substantive issues in the request.

In 2006, Alabama Power initiated the process of developing an application to relicense the Martin hydroelectric project located on the Tallapoosa River. The current Martin license will expire in 2013 and the application for a new license is expected to be filed with the FERC in 2011. In 2010, Alabama Power initiated the process of developing an application to relicense the Holt hydroelectric project located on Warrior River. The current Holt license will expire in August 2015 and the application for a new license is expected to be filed prior to that time.

In 2007, Georgia Power began the relicensing process for Bartlett's Ferry which is located on the Chattahoochee River near Columbus, Georgia. The current Bartlett's Ferry license expires in 2014 and the application for a new license is expected to be submitted to the FERC in 2012.

The ultimate outcome of these matters cannot be determined at this time. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Alabama Power in Item 7 herein for additional information.

Georgia Power and OPC also have a license, expiring in 2027, for the Rocky Mountain Plant, a pure pumped storage facility of 847,800 kilowatt capacity. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Licenses for all projects, excluding those discussed above, expire in the period 2023-2034 in the case of Alabama Power's projects and in the period 2020-2039 in the case of Georgia Power's projects.

Upon or after the expiration of each license, the United States Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property.

Nuclear Regulation

Alabama Power, Georgia Power, and Southern Nuclear are subject to regulation by the NRC. The NRC is responsible for licensing and regulating nuclear facilities and materials and for conducting research in support of the licensing and regulatory process, as mandated by the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and the Nuclear Nonproliferation Act of 1978; and in accordance with the National Environmental Policy Act of 1969, as amended, and other applicable statutes. These responsibilities also include protecting public health and safety, protecting the environment, protecting and safeguarding nuclear materials and nuclear power plants in the interest of national security, and assuring conformity with antitrust laws.

In January 2002, the NRC extended the licenses of Georgia Power's Plant Hatch Units 1 and 2 until 2034 and 2038, respectively. In May 2005, the NRC extended the licenses of Alabama Power's Plant Farley Units 1 and 2 until 2037 and 2041, respectively. In June 2009, the NRC extended the licenses of Plant Vogtle Units 1 and 2 to 2047 and 2049, respectively.

In August 2009, the NRC issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of Georgia Power, OPC, MEAG Power, and City of Dalton (collectively, Owners), related to two additional nuclear units on the site of Plant Vogtle (Plant Vogtle Units 3 and 4). In March 2008, Southern Nuclear filed an application with the NRC for a combined construction and operating license (COL) for Plant Vogtle Units 3 and 4, which, if licensed by the NRC, are scheduled to be placed in service in 2016 and 2017, respectively. Georgia Power currently expects to receive the Vogtle 3 and 4 COLs from the NRC in late 2011 based on the NRC's February 16, 2011 release of its COL schedule framework. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Construction - Nuclear" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power - Nuclear Construction" and Georgia Power under "Construction - Nuclear" in Item 8 herein for additional information.

See Notes 1 and 9 to the financial statements of Southern Company, Alabama Power, and Georgia Power in Item 8 herein for information on nuclear decommissioning costs and nuclear insurance.

Environmental Statutes and Regulations

Southern 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. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions or market-based rates for Southern Power. There is no assurance, however, that all such costs will be recovered.

Compliance with the federal Clean Air Act and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional operating company, Southern Power, and SEGCO. In addition, existing environmental laws and regulations may be changed or new laws and regulations may be adopted or otherwise become applicable to Southern Company, the traditional operating companies, Southern Power, or SEGCO, including laws and regulations designed to address global climate change, air quality, water quality, management of waste materials and coal combustion byproducts, including coal ash, or other environmental, public health, and welfare concerns. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS

POTENTIAL – "Environmental Matters" of Southern Company and each of the traditional operating companies in Item 7 herein for additional information about the Clean Air Act and other environmental issues, including, but not limited to, the litigation brought by the EPA under the New Source Review provisions of the Clean Air Act, possible additional and/or revised regulations related to air and water quality, possible climate change legislation and regulation, and possible regulation of coal combustion byproducts. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 herein for information about environmental issues, possible climate change legislation and regulation and possible regulation of coal combustion byproducts.

Southern Company, the traditional operating companies, Southern Power, and SEGCO are unable to predict at this time what additional steps they may be required to take as a result of the implementation of existing or future requirements pertaining to climate change, air quality, water quality, and management of waste materials and coal combustion byproducts, including coal ash, but such steps could adversely affect system operations and result in substantial additional costs. For example, potential regulations relating to air quality could require the installation of additional environmental controls, potential regulations relating to water quality could require the installation of cooling towers at certain existing generating units, and potential regulations relating to coal combustion byproducts could require closure of or significant change to existing storage units and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements.

Depending on the final outcome of the wide range of proposed environmental regulations currently under consideration by the EPA, the retirement and replacement of certain existing generating units may be more economically efficient than installing required controls necessary to remain in compliance. In addition, while the outcome of these matters cannot now be determined, potential additional environmental regulations could result in delays in obtaining appropriate licenses for generating facilities, increased construction and operating costs, or reduced generation, the nature and extent of which, while not determinable at this time, could be substantial. See "Construction Program" herein for additional information.

Rate Matters

Rate Structure and Cost Recovery Plans

The rates and service regulations of the traditional operating companies are uniform for each class of service throughout their respective service areas. Rates for residential electric service are generally of the block type based upon kilowatt-hours used and include minimum charges. Residential and other rates contain separate customer charges. Rates for commercial service are presently of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer and include rates with special features to encourage off-peak usage. Additionally, Alabama Power, Gulf Power, and Mississippi Power are generally allowed by their respective state PSCs to negotiate the terms and cost of service to large customers. Such terms and cost of service, however, are subject to final state PSC approval.

Fuel and net purchased energy costs are recovered through specific fuel cost recovery provisions at the traditional operating companies. These fuel cost recovery provisions are adjusted to reflect increases or decreases in such costs as needed. Gulf Power's and Mississippi Power's fuel cost recovery provisions are adjusted annually to reflect increases or decreases in such costs. Georgia Power is currently required to file its next fuel case by March 1, 2011, with a new rate to be effective June 1, 2011. Alabama Power's fuel cost recovery rates are adjusted as required; a new rate is scheduled to be effective on April 1, 2011. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in current rates.

Approved environmental compliance and storm damage costs are recovered at Alabama Power and Mississippi Power through cost recovery provisions approved by their respective state PSCs. Within limits approved by their respective PSCs, these rates are adjusted to reflect increases or decreases in such costs as required.

Georgia Power's environmental compliance costs are recovered through its ECCR tariff. On December 21, 2010, the Georgia PSC voted to approve the 2010 ARP effective January 1, 2011 and continuing through December 31, 2013 under which the ECCR tariff has been continued. See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Retail Rate Plans" and Georgia Power under "Retail Regulatory Matters – Rate Plans" in Item 8 herein for additional information.

See "Integrated Resource Planning" herein for a discussion of Georgia PSC certification of new demand-side or supply-side resources for Georgia Power. In addition, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Construction – Nuclear" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and Georgia Power under "Construction – Nuclear" in Item 8 herein for a discussion of the Georgia Nuclear Energy Financing Act and the Georgia PSC certification of Plant Vogtle Units 3 and 4, which allow Georgia Power to recover financing costs for construction of the new nuclear units during the construction period beginning in 2011. On December 21, 2010, as a part of the 2010 ARP, the Georgia PSC approved Georgia Power's Nuclear Construction Cost Recovery tariff effective January 1, 2011.

Alabama Power recovers the cost of certificated new plant and purchased power capacity through cost recovery provisions which are approved annually. Gulf Power files a rate clause request annually with the Florida PSC to recover costs associated with purchased power capacity, energy conservation, and environmental compliance. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in current rates.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters" of Southern Company and each of the traditional operating companies in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters" and Note 3 to the financial statements of each of the traditional operating companies under "Retail Regulatory Matters" in Item 8 herein for a discussion of rate matters. Also, see Note 1 to the financial statements of Southern Company and each of the traditional operating companies in Item 8 herein for a discussion of recovery of fuel costs, storm damage costs, and environmental compliance costs through rates.

The traditional operating companies, Southern Power and its generation subsidiaries, and Southern Renewable Energy's generation subsidiary are authorized by the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

Integrated Resource Planning

Each of the traditional operating companies continually evaluates its electric generating resources in order to ensure that it maintains a cost-effective and reliable mix of resources to meet the existing and future demand requirements of its customers. See "Environmental Statutes and Regulations" above for a discussion of existing and potential environmental regulations that may impact the future generating resource needs of the traditional operating companies.

Certain of the traditional operating companies periodically file IRPs with their respective state PSC. The following is a summary of the most recent IRP filings by certain of the traditional operating companies.

Georgia Power

Triennially, Georgia Power must file an IRP with the Georgia PSC that specifies how it intends to meet the future electrical needs of its customers through a combination of demand-side and supply-side resources. The Georgia PSC, under state law, must certify any new demand-side or supply-side resources for Georgia Power to get cost recovery. Once certified, the lesser of actual or certified construction costs and purchased power costs is recoverable through rates.

On January 29, 2010, Georgia Power filed its 2010 IRP with the Georgia PSC. The 2010 IRP projected that Georgia Power's current supply-side and demand-side resources are sufficient to provide a cost-effective and reliable source of capacity and energy at least through 2014. The 2010 IRP identified a number of potential new or modified federal environmental statutes and regulations that could significantly impact Georgia Power's existing coal-fired generating units. In addition, under the State of Georgia's Multi-Pollutant Rule, Georgia Power is required to install specific emissions controls on certain coal-fired generating units by specific dates between December 31, 2008 and

June 1, 2015. See “Environmental Statutes and Regulations” above.

On July 6, 2010, the Georgia PSC approved Georgia Power’s 2010 IRP including the following provisions: (1) restarting an RFP to enable the potential replacement of coal units that may be retired beginning in approximately 2015; (2) expanding energy efficiency efforts; (3) implementing seven new demand-side management and energy efficiency programs; (4) collecting incentives totaling 10% of the net benefit of energy efficiency programs annually, with certain conditions, for the certified programs; (5) developing a one megawatt self-build portfolio of solar photovoltaic demonstration projects; (6) delaying capital spending on the conversion of Plant Mitchell Unit 3 from a coal-fired generating unit to a renewable biomass generating unit until the EPA issues applicable maximum achievable control technology (MACT) standards under the Clean Air Act; (7) considering conversion of additional coal units to biomass, if such conversions appear to be economic and feasible; and (8) continuing to suspend work on environmental controls for Units 6 and 7 at Plant Yates and Units 1 and 2 at Plant Branch until the EPA issues applicable MACT standards and regulations for coal combustion byproducts.

In addition, Georgia Power’s 2010 IRP reflected the construction of Plant McDonough Units 4, 5, and 6 (natural gas) and Plant Vogtle Units 3 and 4 (nuclear) as certified by the Georgia PSC in 2007 and 2009, respectively. In addition, the 2010 IRP also reflected the related retirement of Plant McDonough Units 1 and 2 (coal), which were decertified by the Georgia PSC in connection with construction of the new units. See MANAGEMENT’S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — “Construction” of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under “Retail Regulatory Matters – Georgia Power – Nuclear Construction” and “Retail Regulatory Matters – Georgia Power – Other Construction” in Item 8 herein and Note 3 to the financial statements of Georgia Power under “Construction” in Item 8 herein for additional information

Georgia Power currently expects to file an update to its IRP in June 2011. Georgia Power is continuing to analyze the potential costs and benefits of installing environmental controls on its remaining coal-fired generating units in light of the potential new or modified environmental regulations. As contemplated in the 2010 IRP, Georgia Power may determine that retiring and replacing certain of these existing units with new generating resources or purchased power is more economically efficient than installing the required environmental controls. On April 20, 2010, Georgia Power issued an RFP for approximately 1,000 megawatts to assure a reliable and economic supply in the event replacement capacity is needed and is currently negotiating with counterparties that offered the most competitive proposals. Certification of any needed resources procured through the RFP would be expected by approximately February 2012.

Under the terms of Georgia Power’s 2010 ARP, any costs associated with changes to Georgia Power’s approved environmental operating or capital budgets (resulting from new or revised environmental regulations) through 2013 that are approved by the Georgia PSC in connection with Georgia Power’s updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. Such costs that may be deferred as a regulatory asset include any impairment losses that may result from a decision to retire certain units that are no longer cost effective in light of new or modified environmental regulations. In addition, in connection with Georgia Power’s 2010 ARP, the Georgia PSC also approved revised depreciation rates that will recover the remaining book value of certain of Georgia Power’s existing coal-fired units by December 31, 2014.

In addition, Georgia Power expects to file a request with the Georgia PSC in spring 2011 for the certification of 562 megawatts of certain wholesale capacity that will be returned to retail service on January 1, 2015 (312 megawatts) and April 1, 2016 (250 megawatts). On September 20, 2010, the Georgia PSC accepted Georgia Power’s offer to return this generating capacity to retail service.

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

Gulf Power

Annually by April 1, Gulf Power must file a 10-year site plan with the Florida PSC containing Gulf Power’s estimate of its power-generating needs in the period and the general location of its proposed power plant sites. The 10-year site plans submitted by the state’s electric utilities are reviewed by the Florida PSC and subsequently classified as either “suitable” or “unsuitable.” The Florida PSC then reports its findings along with any suggested revisions to the Florida Department of Environmental Protection for its consideration at any subsequent electrical power plant site certification proceedings. Under Florida law, any 10-year site plans submitted by an electric utility are considered tentative information for planning purposes only and may be amended at any time at the discretion of the utility with written notification to the Florida PSC. At least every five years, the Florida PSC must conduct proceedings to establish numerical goals for all investor-owned electric utilities and certain municipal or cooperative electric utilities in the state to reduce the growth rates of weather-sensitive peak demand, to reduce and control the growth rates of electric consumption, and to increase the conservation of expensive resources, such as petroleum fuels. Overall residential kilowatts and kilowatt hours goals and overall commercial/industrial kilowatt and kilowatt hours goals for each utility are set by the Florida PSC for each year over a 10-year period. The goals are to be based on an estimate of the total cost effective kilowatts and kilowatt hours savings reasonably achievable through demand-side management in each utility's service area over a 10-year period. Once goals have been set, each affected utility must develop and submit plans and programs to meet the overall goals within its service area to the Florida PSC for review and approval. Once approved, the utilities are required to submit periodic reports which the Florida PSC then uses to prepare its annual report to the Governor and Legislature of the goals that have been established and the progress towards meeting those goals.

Gulf Power's most recent 10-year site plan was classified by the Florida PSC as "suitable" in December 2010. Gulf Power's most recent 10-year site plan and environmental compliance plan identify potential environmental regulations relating to maximum achievable control technology for hazardous air pollutants and potential legislation or regulation that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Byproducts," and "Environmental Matters – Global Climate Issues" of Gulf Power in Item 7 herein. The site plan and environmental compliance plan include preliminary retirement studies under a variety of potential scenarios for units at each of Gulf Power's coal-fired generating plants. These studies indicate that, depending on the final requirements in these anticipated EPA regulations and any legislation or regulations relating to greenhouse gas emissions, as well as estimates of long-term fuel prices, Gulf Power may conclude that it is more economical to retire certain of its coal-fired generating units prior to 2020 and to replace such units with new or purchased capacity.

Also in December 2009, the Florida PSC adopted new numerical conservation goals for Gulf Power along with other electric utilities in the state. The Florida PSC adopted more aggressive goals due in part to the consideration of possible greenhouse gas emissions costs incurred in connection with possible climate change legislation and a change in the manner in which the Florida PSC considers the effect of so-called "free-riders" on the level of conservation reasonably achievable through utility programs. Gulf Power's plans and programs to meet the new goals were submitted to the Florida PSC for review on March 30, 2010 and were approved on January 25, 2011. The costs of implementing Gulf Power's conservation plans and programs are recovered through specific conservation recovery rates set annually by the Florida PSC.

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

Mississippi Power

In December 2009, Mississippi Power filed its 2010 IRP with the Mississippi PSC. The filing was made in connection with the Mississippi PSC certification proceedings relating to a new electric generating plant located in Kemper County, Mississippi that would utilize an IGCC technology. In the 2010 IRP, Mississippi Power projected that it will have a need for new capacity in the 2013 to 2015 timeframe. The 2010 IRP indicated a need range of approximately 200 megawatts to 300 megawatts in 2014, which reflects growth in load and the anticipated retirement of older gas steam units Plant Eaton Units 1 through 3 and Plant Watson Units 1 through 3 in 2012 and 2013, respectively. In addition, due to potential retirements of existing coal units, the Mississippi PSC found a need in 2015 that ranges from 304 megawatts to 1,276 megawatts.

The range of needs for 2015 is based on potential environmental regulations relating to maximum achievable control technology for hazardous air pollutants, as well as potential legislation or regulations that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" and

"Environmental Matters – Global Climate Issues" of Mississippi Power in Item 7 herein. Depending on the final requirements in the anticipated EPA regulations and any legislation or regulation relating to greenhouse gas emissions, as well as estimates of long-term fuel prices, Mississippi Power may conclude that it is more economical to discontinue burning coal at certain coal-fired generating units than to install the required controls.

Mississippi Power's 2010 IRP indicated that Mississippi Power plans to construct the Kemper IGCC to meet its identified needs, to add environmental controls at Plant Daniel Units 1 and 2, to defer environmental controls at Plant Watson Units 4 and 5, and to continue operation of the combined cycle Plant Daniel Units 3 and 4.

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

Mississippi Base Load Construction Legislation

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor in May 2008 to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. The effect of this legislation on Southern Company and Mississippi Power cannot now be determined.

In January 2009, Mississippi Power filed for a CPCN with the Mississippi PSC to allow construction of the Kemper IGCC. On April 29, 2010, the Mississippi PSC issued an order finding that Mississippi Power's application to acquire, construct, and operate the plant did not satisfy the requirement of public convenience and necessity in the form that the project and the related cost recovery were originally proposed by Mississippi Power, unless Mississippi Power accepted certain conditions on the issuance of the CPCN, including a cost cap of approximately $2.4 billion. On May 10, 2010, Mississippi Power filed a motion in response to the April 29, 2010 order of the Mississippi PSC relating to the Kemper IGCC, or in the alternative, for alteration or rehearing of such order.

On May 26, 2010, the Mississippi PSC issued an order revising its findings from the April 29, 2010 order. Among other things, the Mississippi PSC's May 26, 2010 order approved an alternate construction cost cap of up to $2.88 billion (and any amounts that fall within specified exemptions from the cost cap; such exemptions include the costs of the lignite mine and equipment and the carbon dioxide pipeline facilities), subject to determinations by the Mississippi PSC that such costs in excess of $2.4 billion are prudent and required by the public convenience and necessity. On May 27, 2010, Mississippi Power filed a motion with the Mississippi PSC accepting the conditions contained in the order. On June 3, 2010, the Mississippi PSC issued the final certificate order which granted Mississippi Power's motion and issued a CPCN authorizing acquisition, construction, and operation of the plant. The Kemper IGCC, subject to federal and state reviews and certain regulatory approvals, is expected to begin commercial operation in May 2014. See Note 3 to the financial statements of Southern Company and Mississippi Power in Item 8 herein for additional information.

Employee Relations

The Southern Company system had a total of 25,940 employees on its payroll at December 31, 2010.

	Employees at December 31, 2010
Alabama Power	6,552
Georgia Power	8,330
Gulf Power	1,330
Mississippi Power	1,280
SCS	4,465
Southern Holdings*	-
Southern Nuclear	3,676
Southern Power**	-
Other	307
Total	25,940

* Southern Holdings has agreements with SCS whereby all employee services are rendered at cost.

** Southern Power has no employees. Southern Power has agreements with SCS and the traditional operating companies whereby employee services are rendered at amounts in compliance with FERC regulations.

The traditional operating companies have separate agreements with local unions of the IBEW generally covering wages, working conditions, and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance, and construction employees.

Alabama Power has an agreement with the IBEW covering wages and working conditions which is in effect through August 15, 2014.

Georgia Power has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2011. Upon notice given at least 60 days prior to that date, negotiations will be initiated with respect to agreement terms to be effective after such date.

Gulf Power has an agreement with the IBEW covering wages and working conditions, which is in effect through September 14, 2014.

Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect through August 15, 2014.

Southern Nuclear and the IBEW ratified a labor agreement for certain employees at Plants Hatch and Vogtle on May 21, 2009. The agreement is effective through June 30, 2011. Upon notice given at least 60 days prior to June 30, 2011, negotiations may be initiated with respect to a new agreement after such date. A five-year agreement between Southern Nuclear and the IBEW representing certain employees at Plant Farley was ratified on July 8, 2009. The agreement became effective on August 15, 2009 and will remain in effect through August 15, 2014.

Following certification of the United Government Security Officers of America (UGSOA) as the bargaining representative for Southern Nuclear Security Officers at Plant Farley in April 2010, negotiations continue between the UGSOA and Southern Nuclear. A collective bargaining agreement has not yet been ratified.

The agreements also make the terms of the pension plans for the companies discussed above subject to collective bargaining with the unions at either a five-year or a 10-year cycle, depending upon union and company actions.

Item 1A. RISK FACTORS

In addition to the other information in this Form 10-K, including MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL in Item 7 of each registrant, and other documents filed by Southern Company and/or its subsidiaries with the SEC from time to time, the following factors should be carefully considered in evaluating Southern Company and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by, or on behalf of, Southern Company and/or its subsidiaries.

Risks Related to the Energy Industry

Southern Company and its subsidiaries are subject to substantial governmental regulation. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits, and certificates may result in substantial costs to Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, are subject to substantial regulation from federal, state, and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of their businesses, including rates and charges, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices, including any changes in accounting standards, and the operation of fossil-fuel, hydroelectric, solar, and nuclear generating facilities. For example, the rates charged to wholesale customers by the traditional operating companies and by Southern Power must be approved by the FERC. These wholesale rates could be affected absent the ability to conduct business pursuant to FERC market-based rate authority. Additionally, the respective state PSCs must approve the traditional operating companies' requested rates for retail customers. While the retail rates of the traditional operating companies are designed to provide for the full recovery of costs (including a reasonable return on invested capital), there can be no assurance that a state PSC, in a future rate proceeding, will not attempt to alter the timing or amount of certain costs for which recovery is sought or to modify the current authorized rate of return.

Southern Company and its subsidiaries believe the necessary permits, approvals, and certificates have been obtained for their respective existing operations and that their respective businesses are conducted in accordance with applicable laws; however, the impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries cannot now be predicted. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs.

Risks Related to Environmental and Climate Change Legislation , Regulation, and Litigation

Southern Company's, the traditional operating companies', and Southern Power's costs of compliance with environmental laws are significant. The costs of compliance with future environmental laws, including laws and regulations designed to address global climate change, renewable energy standards, air and water quality, coal combustion byproducts, and other matters and the incurrence of environmental liabilities could affect unit retirement decisions and negatively impact the net income, cash flows, and financial condition of Southern Company, the traditional operating companies, or Southern Power.

Southern Company, the traditional operating companies, and Southern Power are subject to extensive federal, state, and local environmental requirements which, among other things, regulate air emissions, water usage and discharges, and the management of hazardous and solid waste in order to adequately protect the environment. Compliance with these legal requirements requires Southern Company, the traditional operating companies, and Southern Power to commit significant expenditures for installation of pollution control equipment, environmental monitoring, emissions fees, and permits at all of their respective facilities. These expenditures are significant and Southern Company, the traditional operating companies, and Southern Power expect that they will increase in the future. Through 2010, Southern Company had invested approximately $8.1 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $500 million, $1.3 billion, and $1.6 billion for 2010, 2009, and 2008, respectively. Southern Company expects that capital expenditures to comply with existing statutes and regulations will be $341 million, $427 million, and $452 million for 2011, 2012, and 2013, respectively. In addition, the Southern Company system currently estimates that potential incremental investments to comply with anticipated new environmental regulations could range from $74 million to $289 million in 2011, $191 million to $670 million in 2012, and $476 million to $1.9 billion in 2013. The 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 proposed environmental legislation and regulations, the cost, availability, and existing inventory of emissions allowances, and the fuel mix of the electric utilities. The ultimate outcome cannot be determined at this time.

If Southern Company, any traditional operating company, or Southern Power fails to comply with environmental laws and regulations, even if caused by factors beyond its control, that failure may result in the assessment of civil or criminal penalties and fines. The EPA has filed civil actions against Alabama Power and Georgia Power and issued notices of violation to Gulf Power and Mississippi Power alleging violations of the new source review provisions of the Clean Air Act. Southern Company is also a party to suits alleging that emissions of carbon dioxide, a greenhouse gas, contribute to global climate change. An adverse outcome in any of these matters could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect unit retirement and replacement decisions, and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates for the traditional operating companies or market-based rates for Southern Power.

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 United States. 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.

Existing environmental laws and regulations may be revised or new laws and regulations related to global climate change, air quality, water quality, coal combustion byproducts, including coal ash, or other environmental and health concerns may be adopted or become applicable to Southern Company, the traditional operating companies, and Southern Power. For example, the regulation of greenhouse gas emissions through legislation or regulation has been, and continues to be, a focus of the current Administration. Although federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable energy standards, and/or energy efficiency standards failed to pass before the end of the 2010 session, such proposals are expected to continue to be considered in the future.

While climate legislation has yet to be adopted, the EPA is moving forward with the regulation of greenhouse gas emissions 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 modifications 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.

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.

Additionally, during 2010 the EPA proposed revisions, revised or issued additional regulations and designations with respect to air quality under the Clean Air Act, including eight-hour ozone standards, sulfur dioxide and nitrogen dioxide standards, a replacement to the Clean Air Interstate Rule relating to nitrogen oxide and sulfur dioxide emissions, and continues to work on a proposed Maximum Achievable Control Technology rule for coal and oil-fired electric generating units, which will likely address numerous hazardous air pollutants, including mercury.

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. Southern Company regards these estimates as pre-screening figures that should be distinguished from the more formalized cost estimates Southern 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 cost impact of such legislation, regulation, new interpretations, or international negotiations would depend upon the specific requirements enacted and cannot be determined at this time. Although the outcome of such legislation, regulation, new interpretations, or international negotiations cannot be determined at this time, legislation or regulation related to greenhouse gas emissions, renewable energy standards, air and water quality, coal combustion byproducts and other matters, individually or together, are likely to result in significant and additional compliance costs, including significant capital expenditures, and could result in additional operating restrictions. These costs will affect future unit retirement and replacement decisions, and could result in the retirement of a significant number of coal-fired generating units of the traditional operating companies. Moreover, the traditional operating companies could incur additional material asset retirement obligations with respect to closing existing coal combustion byproduct storage facilities. Additional compliance costs and costs related to potential unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered from customers. 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.

Risks Related to Southern Company and its Business

The regional power market in which Southern Company and its utility subsidiaries compete may have changing transmission regulatory structures, which could affect the ownership of these assets and related revenues and expenses.

The traditional operating companies currently own and operate transmission facilities as part of a vertically integrated utility. A small percentage of transmission revenues are collected through the wholesale electric tariff but the majority of transmission revenues are collected through retail rates. Ongoing FERC efforts that may potentially change the regulatory and/or operational structure of transmission could have an adverse impact on future revenues. In addition, pending FERC regulation pertaining to cost allocation could require the Southern Company and its utility subsidiaries to subsidize costs outside its service territory. The financial condition, net income, and cash flows of Southern Company and its utility subsidiaries could be adversely affected by pending or future changes in the federal regulatory or operational structure of transmission.

The net income of Southern Company, the traditional operating companies, and Southern Power could be negatively impacted by competitive activity in the wholesale electricity markets.

Competition at the wholesale level continues to evolve in the electricity markets. As a result of changes in federal law and regulatory policy, competition in the wholesale electricity markets has increased due to greater participation by traditional electricity suppliers, non-utility generators, IPPs, wholesale power marketers, and brokers. FERC rules related to transmission are designed to facilitate competition in the wholesale market on a nationwide basis by providing greater flexibility and more choices to wholesale power customers, including initiatives designed to promote and encourage the integration of renewable sources of supply. Moreover, along with transactions contemplating physical delivery of energy, futures contracts and derivatives are traded on various commodities exchanges. Southern Company, the traditional operating companies, and Southern Power cannot predict the impact of these and other such developments, nor can they predict the effect of changes in levels of wholesale supply and demand, which are typically driven by factors beyond their control.

Southern Company may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay upstream dividends or repay funds to Southern Company.

Southern Company is a holding company and, as such, Southern Company has no operations of its own. Substantially all of Southern Company's consolidated assets are held by subsidiaries. Southern Company's ability to meet its financial obligations and to pay dividends on its common stock is primarily dependent on the net income and cash flows of its subsidiaries and their ability to pay upstream dividends or to repay funds to Southern Company. Prior to funding Southern Company, Southern Company's subsidiaries have regulatory restrictions and financial obligations that must be satisfied, including among others, debt service and preferred and preference stock dividends. Southern Company's subsidiaries are separate legal entities and have no obligation to provide Southern Company with funds for its payment obligations.

The financial performance of Southern Company and its subsidiaries may be adversely affected if they are unable to successfully operate their facilities or perform certain corporate functions.

The financial performance of Southern Company and its subsidiaries depends on the successful operation of its subsidiaries' electric generating, transmission, and distribution facilities. Operating these facilities involves many risks, including:

- operator error or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- terrorist attacks;
- fuel or material supply interruptions;
- compliance with mandatory reliability standards, including mandatory cyber security standards;
- information technology system failure;
- cyber intrusion; and
- catastrophic events such as fires, earthquakes, explosions, floods, droughts, hurricanes, pandemic health events such as influenzas, or other similar occurrences.

A decrease or elimination of revenues from the electric generation, transmission, or distribution facilities or an increase in the cost of operating the facilities would reduce the net income and cash flows and could adversely impact the financial condition of the affected traditional operating company or Southern Power and of Southern Company.

With respect to Southern Company's investments in leverage leases, the recovery of its investment is dependent on the profitable operation of the leased assets by the respective lessees. A significant deterioration in the performance of the leased asset could result in the impairment of the related lease receivable.

The traditional operating companies and Southern Power could be subject to higher costs and penalties as a result of mandatory reliability standards.

As a result of the Energy Policy Act of 2005, owners and operators of bulk power transmission systems, including the traditional operating companies, are subject to mandatory reliability standards enacted by the North American Reliability Corporation and enforced by the FERC. Compliance with the mandatory reliability standards may subject the traditional operating companies, Southern Power, and Southern Company to higher operating costs and may result in increased capital expenditures. If any traditional operating company or Southern Power is found to be in noncompliance with the mandatory reliability standards, the traditional operating company and Southern Power could be subject to sanctions, including substantial monetary penalties.

The revenues of Southern Company, the traditional operating companies, and Southern Power depend in part on sales under PPAs. The failure of a counterparty to one of these PPAs to perform its obligations, or the failure to renew the PPAs, could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company.

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. In addition, the traditional operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. Even though Southern Power and the traditional operating companies have a rigorous credit evaluation process, the failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company. Although these credit evaluations take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than the credit evaluation predicts. Additionally, neither Southern Power nor any traditional operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. If a PPA is not renewed, a replacement PPA cannot be assured.

Southern Company, the traditional operating companies, and Southern Power may incur additional costs or delays in the construction of new plants or other facilities and may not be able to recover their investments. The facilities of the traditional operating companies and Southern Power require ongoing capital expenditures.

The businesses of the registrants require substantial capital expenditures for investments in new facilities and capital improvements to transmission, distribution, and generation facilities, including those to meet environmental standards. Certain of the traditional operating companies and Southern Power are in the process of constructing new generating facilities and adding environmental controls equipment at existing generating facilities. Southern Company intends to continue its strategy of developing and constructing other new facilities, including new nuclear generating, combined cycle, IGCC, and biomass generating units, expanding existing facilities, and adding environmental control equipment. These types of projects are long-term in nature and may involve facility designs that have not been finalized or previously constructed. The completion of these types of projects without delays or significant cost overruns is subject to substantial risks, including:

- shortages and inconsistent quality of equipment, materials, and labor;
- work stoppages;

- contractor or supplier non-performance under construction or other agreements;
- delays in or failure to receive necessary permits, approvals, and other regulatory authorizations;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- continued public and policymaker support for such projects;
- adverse weather conditions;
- unforeseen engineering problems;
- changes in project design or scope;
- environmental and geological conditions;
- delays or increased costs to interconnect facilities to transmission grids; and
- unanticipated cost increases, including materials and labor.

In addition, with respect to the construction of new nuclear units, a major incident at a nuclear facility anywhere in the world could cause the NRC to delay or prohibit construction of new nuclear units. If a traditional operating company or Southern Power is unable to complete the development or construction of a facility or decides to delay or cancel construction of a facility, it may not be able to recover its investment in that facility and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Even if a construction project is completed, the total costs may be higher than estimated and there is no assurance that the traditional operating company will be able to recover such expenditures through regulated rates. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of a traditional operating company or Southern Power and of Southern Company. Construction delays also may result in the loss of otherwise available investment tax credits and other tax incentives. Furthermore, if construction projects are not completed according to specification, a traditional operating company or Southern Power and Southern Company may incur liabilities and suffer reduced plant efficiency, higher operating costs, and reduced net income.

Once facilities come into commercial operation, ongoing capital expenditures are required to maintain reliable levels of operation. Significant portions of the traditional operating companies' existing facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements, or to provide reliable operations.

Changes in technology may make Southern Company's electric generating facilities owned by the traditional operating companies and Southern Power less competitive.

A key element of the business model of Southern Company, the traditional operating companies, and Southern Power is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, and solar cells. It is possible that advances in technology will reduce the cost of alternative methods of producing power to a level that is competitive with that of most central station power electric production. If this were to happen and if these technologies achieved economies of scale, the market share of Southern Company, the traditional operating companies, and Southern Power could be eroded, and the value of their respective electric generating facilities could be reduced. It is also possible that rapid advances in central station power generation technology could reduce the value of the current electric generating facilities owned by Southern Company, the traditional operating companies, and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional operating companies, or Southern Power.

Operation of nuclear facilities involves inherent risks, including environmental, health, regulatory, terrorism, and financial risks, that could result in fines or the closure of Southern Company's nuclear units owned by Alabama Power or Georgia Power and which may present potential exposures in excess of insurance coverage.

Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units and the construction of Plant Vogtle Units 3 and 4. The six existing units are operated by Southern Nuclear and represent approximately 3,680 megawatts, or 8.6%, of Southern Company's generation capacity as of December 31, 2010. Nuclear facilities are subject to environmental, health, and financial risks such as on-site storage of spent nuclear fuel, the ability to dispose of such spent nuclear fuel, the ability to maintain adequate reserves for decommissioning, potential liabilities arising out of the operation of these facilities, and the threat of a possible terrorist attack. Alabama Power and Georgia Power maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks; however, it is possible that damages could exceed the amount of insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down any unit, depending upon its assessment of the severity of the situation, until compliance is achieved. NRC orders or regulations related to increased security measures and any future safety requirements promulgated by the NRC could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants. In addition, although Alabama Power, Georgia Power, and Southern Company have no reason to anticipate a serious nuclear incident at their plants, if an incident did occur, it could result in substantial costs to Alabama Power or Georgia Power and Southern Company. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

In addition, potential terrorist threats and increased public scrutiny of utilities could result in increased nuclear licensing or compliance costs that are difficult or impossible to predict.

The generation operations and energy marketing operations of Southern Company, the traditional operating companies, and Southern Power are subject to risks, many of which are beyond their control, including changes in power prices and fuel costs, that may reduce Southern Company's, the traditional operating companies', and Southern Power's revenues and increase costs.

The generation operations and energy marketing operations of Southern Company, the traditional operating companies, and Southern Power are subject to changes in power prices or fuel costs, which could increase the cost of producing power or decrease the amount Southern Company, the traditional operating companies, and Southern Power receive from the sale of power. The market prices for these commodities may fluctuate significantly over relatively short periods of time. In addition, the proportion of natural gas generation to the total fuel mix is likely to increase in the future. Southern Company, the traditional operating companies, and Southern Power attempt to mitigate risks associated with fluctuating fuel costs by passing these costs on to customers through the traditional operating companies' fuel cost recovery clauses or through PPAs. Among the factors that could influence power prices and fuel costs are:

- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels used in the generation facilities of the traditional operating companies and Southern Power including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;
- liquidity in the general wholesale electricity market;
- weather conditions impacting demand for electricity;
- seasonality;

- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;
- the financial condition of market participants;
- the economy in the service territory, the nation, and worldwide, including the impact of economic conditions on industrial and commercial demand for electricity and the worldwide demand for fuels;
- natural disasters, wars, embargos, acts of terrorism, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

Certain of these factors could increase the expenses of the traditional operating companies or Southern Power and Southern Company. For the traditional operating companies, such increases may not be fully recoverable through rates. Other of these factors could reduce the revenues of the traditional operating companies or Southern Power and Southern Company.

Historically, the traditional operating companies from time to time have experienced underrecovered fuel cost balances and deficits in their storm cost recovery reserve balances and may experience such balances in the future. While the traditional operating companies are generally authorized to recover underrecovered fuel costs through fuel cost recovery clauses and storm recovery costs through special rate provisions administered by the respective PSCs, recovery may be denied if costs are deemed to be imprudently incurred and delays in the authorization of such recovery could negatively impact the cash flows of the affected traditional operating company and Southern Company.

A downgrade in the credit ratings of Southern Company, the traditional operating companies, or Southern Power could negatively affect their ability to access capital at reasonable costs and/or could require Southern Company, the traditional operating companies, or Southern Power to post collateral or replace certain indebtedness.

There are a number of factors that rating agencies evaluate to arrive at credit ratings for Southern Company, the traditional operating companies, and Southern Power, including capital structure, regulatory environment, the ability to cover liquidity requirements, and other commitments for capital. Southern Company, the traditional operating companies, and Southern Power could experience a downgrade in their ratings if any of the rating agencies conclude that the level of business or financial risk of the industry or Southern Company, the traditional operating companies, or Southern Power has deteriorated. Changes in ratings methodologies by the agencies could also have a negative impact on credit ratings. If one or more rating agencies downgrade Southern Company, the traditional operating companies, or Southern Power, borrowing costs would increase, its pool of investors and funding sources would likely decrease, and, particularly for any downgrade to below investment grade, significant collateral requirements may be triggered in a number of contracts.

The use of derivative contracts by Southern Company and its subsidiaries in the normal course of business could result in financial losses that negatively impact the net income of Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, use derivative instruments, such as swaps, options, futures, and forwards, to manage their commodity and interest rate exposures and, to a lesser extent, engage in limited trading activities. Southern Company and its subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, limits, and procedures. These risk management policies, limits, and procedures might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, derivative contracts entered for hedging purposes might not off-set the underlying exposure being hedged as expected resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. The factors used in the valuation of these instruments become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

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 Southern Company and its subsidiaries. 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.

The traditional operating companies and Southern Power may not be able to obtain adequate fuel supplies, which could limit their ability to operate their facilities.

The traditional operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, fuel oil, and biomass, from a number of suppliers. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting any of these fuel suppliers, could limit the ability of the traditional operating companies and Southern Power to operate their respective facilities, and thus reduce the net income of the affected traditional operating company or Southern Power and Southern Company.

The traditional operating companies are dependent on coal for much of their electric generating capacity. Each traditional operating company has coal supply contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal to the traditional operating companies. The suppliers under these agreements may experience financial or technical problems which inhibit their ability to fulfill their obligations to the traditional operating companies. In addition, the suppliers under these agreements may not be required to supply coal to the traditional operating companies under certain circumstances, such as in the event of a natural disaster. If the traditional operating companies are unable to obtain their coal requirements under these contracts, the traditional operating companies may be required to purchase their coal requirements at higher prices, which may not be fully recoverable through rates.

In addition, the traditional operating companies and Southern Power to a greater extent are dependent on natural gas for a portion of their electric generating capacity. Natural gas supplies can be subject to disruption in the event production or distribution is curtailed, such as in the event of a hurricane.

In addition, world market conditions for fuels can impact the availability of natural gas, coal, and uranium.

Demand for power could exceed supply capacity, resulting in increased costs for purchasing capacity in the open market or building additional generation capabilities.

Through the traditional operating companies and Southern Power, Southern Company is currently obligated to supply power to retail customers and wholesale customers under long-term PPAs. At peak times, the demand for power required to meet this obligation could exceed Southern Company's available generation capacity. Market or competitive forces may require that the traditional operating companies or Southern Power purchase capacity on the open market or build additional generation capabilities. Because regulators may not permit the traditional operating companies to pass all of these purchase or construction costs on to their customers, the traditional operating companies may not be able to recover any of these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of purchased or constructed capacity and the traditional operating companies' recovery in customers' rates. Under Southern Power's long-term fixed price PPAs, Southern Power would not have the ability to recover any of these costs. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and Southern Company.

Demand for power could decrease or fail to grow at expected rates, resulting in stagnant or reduced revenues, limited growth opportunities, and potentially stranded generation assets.

Southern Company, the traditional operating companies, and Southern Power each engage in a long-term planning process to determine the optimal mix and timing of new generation assets required to serve future load obligations. This planning process must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including regional economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional operating companies to adjust rates to recover the costs of new generation assets while such assets are being constructed, the traditional operating companies may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of additional capacity and the traditional operating companies' recovery in customers' rates. Under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if market prices drop below original forecasts. Southern Power may not be able to extend its existing PPAs or to find new buyers for existing generation assets as existing PPAs expire, or it may be forced to market these assets at prices lower than originally intended. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and Southern Company.

The operating results of Southern Company, the traditional operating companies, and Southern Power are affected by weather conditions and may fluctuate on a seasonal and quarterly basis. In addition, significant weather events, such as hurricanes, tornadoes, floods, and droughts, or a terrorist attack could result in substantial damage to or limit the operation of the properties of the traditional operating companies and Southern Power and could negatively impact results of operation, financial condition, and liquidity.

Electric power supply is generally a seasonal business. In many parts of the country, demand for power peaks during the summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power in the future may fluctuate substantially on a seasonal basis. In addition, the traditional operating companies and Southern Power have historically sold less power when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net income, available cash, and borrowing ability of Southern Company, the traditional operating companies, and Southern Power.

In addition, volatile or significant weather events or a terrorist attack could result in substantial damage to the transmission and distribution lines of the traditional operating companies and the generating facilities of the traditional operating companies and Southern Power. The traditional operating companies and Southern Power have significant investments in the Atlantic and Gulf Coast regions which could be subject to major storm activity. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities.

Each traditional operating company maintains a reserve for property damage to cover the cost of damages from weather events to its transmission and distribution lines and the cost of uninsured damages to its generating facilities and other property. In the event a traditional operating company experiences any of these weather events or any natural disaster, or other catastrophic event, such as a terrorist attack, recovery of costs in excess of reserves and insurance coverage is subject to the approval of its state PSC. While the traditional operating companies generally are entitled to recover prudently incurred costs incurred in connection with such an event, any denial by the applicable state PSC or delay in recovery of any portion of such costs could have a material negative impact on a traditional operating company's and Southern Company's results of operations, financial condition, and liquidity.

In addition, damages resulting from significant weather events within the service territory of any traditional operating company or affecting Southern Power's customers may result in the loss of customers and reduced demand for electricity for extended periods. For example, Hurricane Katrina hit the Gulf Coast of Mississippi in August 2005 and caused substantial damage within Mississippi Power's service territory. As of December 31, 2010, Mississippi Power had approximately 4.3% fewer retail customers as compared to pre-storm levels. Any significant loss of customers or reduction in demand for electricity could have a material negative impact on a traditional operating company's, Southern Power's, and Southern Company's results of operations, financial condition, and liquidity.

Failure to attract and retain an appropriately qualified workforce could negatively impact Southern Company's and its subsidiaries' results of operations.

Events such as an aging workforce without appropriate replacements, mismatch of skillset to future needs, or unavailability of contract resources may lead to operating challenges or increased costs. Such operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development, especially with the workforce needs associated with new nuclear construction. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Southern Company and its subsidiaries' ability to manage and operate their businesses. If Southern Company and its subsidiaries, including the traditional operating companies, are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

Risks Related to Market and Economic Volatility

The business of Southern Company, the traditional operating companies, and Southern Power is dependent on their ability to successfully access funds through capital markets and financial institutions. The inability of Southern Company, any traditional operating company, or Southern Power to access funds may limit its ability to execute its business plan by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows.

Southern Company, the traditional operating companies, and Southern Power rely on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flow from their respective operations. If Southern Company, any traditional operating company, or Southern Power is not able to access capital at competitive rates, its ability to implement its business plan will be limited by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows. In addition, Southern Company, the traditional operating companies, and Southern Power rely on committed bank lending agreements as back-up liquidity which allows them to access low cost money markets. Each of Southern Company, the traditional operating companies, and Southern Power believes that it will maintain sufficient access to these financial markets based upon current credit ratings. However, certain market disruptions may increase its cost of borrowing or adversely affect its ability to raise capital through the issuance of securities or other borrowing arrangements or its ability to secure committed bank lending agreements used as back-up sources of capital. Such disruptions could include:

- an economic downturn or uncertainty;
- the bankruptcy or financial distress at an unrelated energy company or financial institution;
- capital markets volatility and interruption;
- market prices for electricity and gas;
- terrorist attacks or threatened attacks on Southern Company's facilities or unrelated energy companies' facilities;
- war or threat of war; or
- the overall health of the utility and financial institution industries.

Market performance and other changes may decrease the value of benefit plans and nuclear decommissioning trust assets or may increase plan costs, which then could require significant additional funding.

The performance of the capital markets affects the values of the assets held in trust under Southern Company's pension and postretirement benefit plans and the assets held in trust to satisfy obligations to decommission Alabama Power's and Georgia Power's nuclear plants. Southern Company, Alabama Power, and Georgia Power have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below projected return rates. A decline in the market value of these assets, as has been experienced in prior periods, may increase the funding requirements relating to Southern Company's benefit plan liabilities and Alabama Power's and Georgia Power's nuclear decommissioning obligations. Additionally, changes in interest rates affect the liabilities under Southern Company's pension and postretirement benefit plans; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions, may also increase the funding requirements of the obligations related to the pension benefit plans. Southern Company and its subsidiaries are also facing rising medical benefit costs, including the current costs for active and retired employees. It is possible that these costs may increase at a rate that is significantly higher than anticipated. If Southern Company is unable to successfully manage benefit plan assets and medical benefit costs and Alabama Power and Georgia Power are unable to successfully manage the nuclear decommissioning trust funds, results of operations and financial position could be negatively affected. Additionally, Southern Company and its subsidiaries may also be affected by healthcare legislation.

Southern Company, the traditional operating companies, and Southern Power are subject to risks associated with a changing economic environment, which could impact their ability to obtain adequate insurance and the financial stability of the customers of the traditional operating companies and Southern Power.

The financial condition of some insurance companies, the threat of terrorism, and the hurricanes that affected the Gulf Coast, among other things, have had disruptive effects on the insurance industry. The availability of insurance covering risks that Southern Company, the traditional operating companies, Southern Power, and their respective competitors typically insure against may decrease, and the insurance that Southern Company, the traditional operating companies, and Southern Power are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms.

Additionally, Southern Company, the traditional operating companies, and Southern Power are exposed to risks related to general economic conditions in their applicable service territory and are thus impacted by the economic cycles of the customers each serves. Any economic downturn or disruption of financial markets could negatively affect the financial stability of the customers and counterparties of the traditional operating companies and Southern Power. As territories served by the traditional operating companies and Southern Power experience economic downturns, energy consumption patterns may change and revenues may be negatively impacted. Additionally, customers could voluntarily reduce their consumption of electricity in response to decreases in their disposable income or individual conservation efforts. If commercial and industrial customers experience economic downturns, their consumption of electricity may decline. As a result, revenues may be negatively impacted.

Further, the results of operations of the traditional operating companies and Southern Power are affected by customer growth in their applicable service territory. Customer growth and customer usage can be affected by economic factors in the service territory of the traditional operating companies and Southern Power and elsewhere, including, for example, job and income growth, housing starts, and new home prices. A population decline and/or business closings in the territory served by the traditional operating companies or Southern Power or slower than anticipated customer growth as a result of the recent recession or otherwise could also have a negative impact on revenues and could result in greater expense for uncollectible customer balances.

As with other parts of the country, the territories served by the traditional operating companies and Southern Power have been impacted by the recent economic recession. The traditional operating companies have experienced some decline in the rate of residential and commercial sales growth, and also have experienced declining sales to commercial and industrial customers due to the recent economic recession. Southern Power is expected to continue to experience reduced future revenues for its requirements customers due to the recent economic recession. The timing and extent of the recovery cannot be predicted.

These and the other factors discussed above could adversely affect Southern Company's, the traditional operating companies', and Southern Power's level of future net income.

Energy conservation and energy price increases could negatively impact financial results.

A number of regulatory and legislative bodies have proposed or introduced requirements and/or incentives to reduce energy consumption by certain dates. Conservation programs could impact the financial results of Southern Company, the traditional operating companies, and Southern Power in different ways. To the extent conservation results in reduced energy demand or significantly slows the growth in demand, the value of wholesale generation assets of the traditional operating companies and Southern Power and other unregulated business activities could be adversely impacted. In addition, conservation could negatively impact the traditional operating companies depending on the regulatory treatment of the associated impacts. If any traditional operating company is required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact on such traditional operating company and Southern Company. Southern Company, the traditional operating companies, and Southern Power could also be impacted if any future energy price increases result in a decrease in customer usage. Southern Company, the traditional operating companies, and Southern Power are unable to determine what impact, if any, conservation and increases in energy prices will have on financial condition or results of operations.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES

Electric Properties

The traditional operating companies, Southern Power, Southern Renewable Energy, and SEGCO, at December 31, 2010, owned and/or operated 33 hydroelectric generating stations, 34 fossil fuel generating stations, three nuclear generating stations, and 12 combined cycle/cogeneration stations, one solar facility, and one landfill gas facility. The amounts of capacity for each company are shown in the table below.

Generating Station	Location	Nameplate Capacity (1)
		(Kilowatts)
FOSSIL STEAM		
Gadsden	Gadsden, AL	120,000
Gorgas	Jasper, AL	1,221,250
Barry	Mobile, AL	1,525,000
Greene County	Demopolis, AL	300,000 (2)
Gaston Unit 5	Wilsonville, AL	880,000
Miller	Birmingham, AL	2,532,288 (3)
Alabama Power Total		6,578,538
Bowen	Cartersville, GA	3,160,000
Branch	Milledgeville, GA	1,539,700
Hammond	Rome, GA	800,000
Kraft	Port Wentworth, GA	281,136
McDonough (4)	Atlanta, GA	490,000
McIntosh	Effingham County, GA	163,117
McManus	Brunswick, GA	115,000
Mitchell	Albany, GA	125,000
Scherer	Macon, GA	750,924 (5)
Wansley	Carrollton, GA	925,550 (6)
Yates	Newnan, GA	1,250,000
Georgia Power Total		9,600,427
Crist	Pensacola, FL	970,000
Daniel	Pascagoula, MS	500,000 (7)
Lansing Smith	Panama City, FL	305,000
Scholz	Chattahoochee, FL	80,000
Scherer Unit 3	Macon, GA	204,500 (5)
Gulf Power Total		2,059,500
Daniel	Pascagoula, MS	500,000 (7)
Eaton	Hattiesburg, MS	67,500
Greene County	Demopolis, AL	200,000 (2)
Sweatt	Meridian, MS	80,000
Watson	Gulfport, MS	1,012,000
Mississippi Power Total		1,859,500
Gaston Units 1-4	Wilsonville, AL	
SEGCO Total		1,000,000 (8)
Total Fossil Steam		21,097,965

Generating Station	Location	Nameplate Capacity (1)
		(Kilowatts)
NUCLEAR STEAM		
Farley	Dothan, AL	
Alabama Power Total		1,720,000
Hatch	Baxley, GA	899,612 (9)
Vogtle	Augusta, GA	1,060,240 (10)
Georgia Power Total		1,959,852
Total Nuclear Steam		3,679,852
COMBUSTION TURBINES		
Greene County	Demopolis, AL	
Alabama Power Total		720,000
Boulevard	Savannah, GA	59,100
Bowen	Cartersville, GA	39,400
Intercession City	Intercession City, FL	47,667 (11)
Kraft	Port Wentworth, GA	22,000
McDonough	Atlanta, GA	78,800
McIntosh Units 1 through 8	Effingham County, GA	640,000
McManus	Brunswick, GA	481,700
Mitchell	Albany, GA	118,200
Robins	Warner Robins, GA	158,400
Wansley	Carrollton, GA	26,322 (6)
Wilson	Augusta, GA	354,100
Georgia Power Total		2,025,689
Lansing Smith Unit A	Panama City, FL	39,400
Pea Ridge Units 1-3	Pea Ridge, FL	15,000
Gulf Power Total		54,400
Chevron Cogenerating Station	Pascagoula, MS	147,292 (12)
Sweatt	Meridian, MS	39,400

Generating Station	Location	Nameplate Capacity (1)
		(Kilowatts)
Watson	Gulfport, MS	39,360
Mississippi Power Total		226,052
Dahlberg	Jackson County, GA	756,000
Oleander	Cocoa, FL	791,301
Rowan	Salisbury, NC	455,250
West Georgia	Thomaston, GA	668,800
Southern Power Total		2,671,351
Gaston **(SEGCO)**	Wilsonville, AL	19,680 (8)
Total Combustion Turbines		5,717,172
COGENERATION		
Washington County	Washington County, AL	123,428
GE Plastics Project	Burkeville, AL	104,800
Theodore	Theodore, AL	236,418
Total Cogeneration		464,646
COMBINED CYCLE		
Barry	Mobile, AL	
Alabama Power Total		1,070,424
McIntosh Units 10&11	Effingham County, GA	
Georgia Power Total		1,318,920
Smith	Lynn Haven, FL	
Gulf Power Total		545,500
Daniel (Leased)	Pascagoula, MS	
Mississippi Power Total		1,070,424
Franklin	Smiths, AL	1,857,820
Harris	Autaugaville, AL	1,318,920
Rowan	Salisbury, NC	530,550
Stanton Unit A	Orlando, FL	428,649 (13)
Wansley	Carrollton, GA	1,073,000
Southern Power Total		5,208,939
Total Combined Cycle		9,214,207
HYDROELECTRIC FACILITIES		
Bankhead	Holt, AL	53,985
Bouldin	Wetumpka, AL	225,000
Harris	Wedowee, AL	132,000
Henry	Ohatchee, AL	72,900
Holt	Holt, AL	46,944
Jordan	Wetumpka, AL	100,000
Lay	Clanton, AL	177,000
Lewis Smith	Jasper, AL	157,500
Logan Martin	Vincent, AL	135,000
Martin	Dadeville, AL	182,000
Mitchell	Verbena, AL	170,000
Thurlow	Tallassee, AL	81,000
Weiss	Leesburg, AL	87,750
Yates	Tallassee, AL	47,000
Alabama Power Total		1,668,079
Bartletts Ferry	Columbus, GA	173,000
Goat Rock	Columbus, GA	38,600
Lloyd Shoals	Jackson, GA	14,400
Morgan Falls	Atlanta, GA	16,800
North Highlands	Columbus, GA	29,600
Oliver Dam	Columbus, GA	60,000
Rocky Mountain	Rome, GA	215,256 (14)
Sinclair Dam	Milledgeville, GA	45,000
Tallulah Falls	Clayton, GA	72,000
Terrora	Clayton, GA	16,000
Tugalo	Clayton, GA	45,000
Wallace Dam	Eatonton, GA	321,300
Yonah	Toccoa, GA	22,500
6 Other Plants		18,080
Georgia Power Total		1,087,536
Total Hydroelectric Facilities		2,755,615
SOLAR		
Cimarron	Springer, NM	
Southern Renewable Total		30,000 (15)
LANDFILL GAS		
Perdido	Escambia County, FL	
Gulf Power Total		3,200
Total Generating Capacity		42,962,657

Notes:

(1) See "Jointly-Owned Facilities" herein for additional information.

(2) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively.

(3) Capacity shown is Alabama Power's portion (91.84%) of total plant capacity.

(4) McDonough Units 1 and 2 are scheduled to be retired in April 2012 and October 2011, respectively.

(5) Capacity shown for Georgia Power is 8.4% of Units 1 and 2 and 75% of Unit 3. Capacity shown for Gulf Power is 25% of Unit 3.

(6) Capacity shown is Georgia Power's portion (53.5%) of total plant capacity.

(7) Represents 50% of the plant which is owned as tenants in common by Gulf Power and Mississippi Power.

(8) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information.

(9) Capacity shown is Georgia Power's portion (50.1%) of total plant capacity.

(10) Capacity shown is Georgia Power's portion (45.7%) of total plant capacity.

(11) Capacity shown represents 33 1/3% of total plant capacity. Georgia Power owns a 1/3 interest in the unit with 100% use of the unit from June through September. Progress Energy Florida operates the unit.

(12) Generation is dedicated to a single industrial customer.

(13) Capacity shown is Southern Power's portion (65%) of total plant capacity.

(14) Capacity shown is Georgia Power's portion (25.4%) of total plant capacity. OPC operates the plant.

(15) The Cimarron solar facility is owned by an indirect subsidiary of Southern Renewable Energy. The kilowatts shown represents 100% of the facility's capacity.

Except as discussed below under "Titles to Property," the principal plants and other important units of the traditional operating companies, Southern Power, and SEGCO are owned in fee by the respective companies. It is the opinion of management of each such company that its operating properties are adequately maintained and are substantially in good operating condition.

Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States is paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2010, the unamortized portion of this cost was approximately $20.6 million.

In 2010, the maximum demand on the traditional operating companies, Southern Power, and SEGCO was 36,321,000 kilowatts and occurred on July 26, 2010. The all-time maximum demand of 38,777,000 kilowatts on the traditional operating companies, Southern Power, and SEGCO occurred on August 22, 2007. These amounts exclude demand served by capacity retained by MEAG Power, OPC, and SEPA. The reserve margin for the traditional operating companies, Southern Power, and SEGCO in 2010 was 23%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information on peak demands for each registrant.

Jointly-Owned Facilities

Alabama Power, Georgia Power, and Southern Power have undivided interests in certain generating plants and other related facilities to or from non-affiliated parties. The percentages of ownership are as follows:

		Percentage Ownership										
	Total Capacity	Alabama Power	Power South	Georgia Power	OPC	MEAG Power	Dalton	Progress Energy Florida	Southern Power	OUC	FMPA	KUA
	(Megawatts)											
Plant Miller Units 1 and 2	1,320	91.8%	8.2%	–%	–%	–%	–%	–%	–%	–%	–%	–%
Plant Hatch	1,796	–	–	50.1	30.0	17.7	2.2	–	–	–	–	–
Plant Vogtle	2,320	–	–	45.7	30.0	22.7	1.6	–	–	–	–	–
Plant Scherer Units 1 and 2	1,636	–	–	8.4	60.0	30.2	1.4	–	–	–	–	–
Plant Wansley	1,779	–	–	53.5	30.0	15.1	1.4	–	–	–	–	–
Rocky Mountain	848	–	–	25.4	74.6	–	–	–	–	–	–	–
Intercession City, FL	143	–	–	33.3	–	–	–	66.7	–	–	–	–
Plant Stanton A	660	–	–	–	–	–	–	–	65%	28%	3.5%	3.5%

Alabama Power and Georgia Power have contracted to operate and maintain the respective units in which each has an interest (other than Rocky Mountain and Intercession City) as agent for the joint owners. SCS provides operation and maintenance services for Plant Stanton A.

In addition, Georgia Power has commitments regarding a portion of a five percent interest in Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the later of retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether any capacity is available. The energy cost is a function of each unit's variable operating costs. Except for the portion of the capacity payments related to the Georgia PSC's disallowances of Plant Vogtle Units 1 and 2 costs, the cost of such capacity and energy is included in purchased power from non-affiliates in Georgia Power's statements of income in Item 8 herein. Also see Note 7 to the financial statements of Georgia Power under "Commitments – Purchased Power Commitments" in Item 8 herein for additional information.

Titles to Property

The traditional operating companies', Southern Power's, and SEGCO's interests in the principal plants (other than certain pollution control facilities, combined cycle units at Plant Daniel leased by Mississippi Power, and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the liens pursuant to pollution control revenue bonds of Alabama Power and Gulf Power on specific pollution control facilities. See Note 6 to the financial statements of Southern Company, Alabama Power, and Gulf Power under "Assets Subject to Lien" and Note 7 to the financial statements of Mississippi Power under "Operating Leases – Plant Daniel Combined Cycle Generating Units" in Item 8 herein for additional information. The traditional operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines and steam heating mains are constructed principally on rights-of-way which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements.

Item 3. LEGAL PROCEEDINGS

(1) United States of America v. Alabama Power (United States District Court for the Northern District of Alabama)

United States of America v. Georgia Power (United States District Court for the Northern District of Georgia)

See Note 3 to the financial statements of Southern Company and each traditional operating company under "Environmental Matters – New Source Review Actions" in Item 8 herein for information.

(2) Environmental Remediation

See Note 3 to the financial statements of Southern Company, Georgia Power, Gulf Power, and Mississippi Power under "Environmental Matters – Environmental Remediation" and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Environmental Compliance Overview Plan" in Item 8 herein for information related to environmental remediation.

(3) Right of Way Litigation

See Note 3 to the financial statements of Southern Company and Mississippi Power under "Right of Way Litigation" in Item 8 herein for information.

See Note 3 to the financial statements of each registrant in Item 8 herein for descriptions of additional legal and administrative proceedings discussed therein.

EXECUTIVE OFFICERS OF SOUTHERN COMPANY

(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2010.

Thomas A. Fanning
Chairman, President, Chief Executive Officer, and Director
Age 53
Elected in 2003. Chairman and Chief Executive Officer since December 1, 2010 and President since August 1, 2010. Previously served as Executive Vice President and Chief Operating Officer from February 2008 through July 31, 2010. He also served as Executive Vice President and Chief Financial Officer from May 2007 through January 2008 and Executive Vice President, Chief Financial Officer, and Treasurer from April 2003 to May 2007.

Art P. Beattie
Executive Vice President and Chief Financial Officer
Age 56
Elected in 2010. Executive Vice President and Chief Financial Officer since August 13, 2010. Previously served as Executive Vice President, Chief Financial Officer, and Treasurer of Alabama Power from February 2005 through August 12, 2010 and Vice President and Comptroller of Alabama Power from 1998 through January 2005.

W. Paul Bowers
Executive Vice President
Age 54
Elected in 2001. Chief Executive Officer, President and Director of Georgia Power since December 31, 2010 and Chief Operating Officer of Georgia Power from August 13, 2010 to December 31, 2010. He previously served as Executive Vice President and Chief Financial Officer of Southern Company from February 2008 to August 12, 2010. He also served as Executive Vice President of Southern Company from May 2007 to February 2008 and as President of Southern Company Generation, a business unit of Southern Company, and Executive Vice President of SCS from May 2001 through January 2008.

Mark A. Crosswhite
President and Chief Executive Officer of Gulf Power
Age 48
Elected in 2010. President, Chief Executive Officer, and Director of Gulf Power since January 1, 2011. Previously served as Executive Vice President of External Affairs at Alabama Power from February 2008 through December 2010 and Senior Vice President and Counsel of Alabama Power from July 2006 through January 2008. He also served as Vice President of SCS from March 2004 through January 2008.

Edward Day, IV
President and Chief Executive Officer of Mississippi Power
Age 50
Elected in 2010. President, Chief Executive Officer, and Director of Mississippi Power since August 13, 2010. Previously served as Executive Vice President for Engineering and Construction Services at Southern Company Generation, a business unit of Southern Company, from May 2003 to August 12, 2010.

G. Edison Holland, Jr.
Executive Vice President, General Counsel, and Secretary
Age 58
Elected in 2001. Executive Vice President and General Counsel since April 2001.

Charles D. McCrary
Executive Vice President
Age 59
Elected in 1998. Executive Vice President since February 2002. He also serves as President, Chief Executive Officer, and Director of Alabama Power since October 2001.

James H. Miller, III
President and Chief Executive Officer of Southern Nuclear
Age 61
Elected in 2008. President and Chief Executive Officer of Southern Nuclear since August 27, 2008. Previously served as Senior Vice President and General Counsel of Georgia Power from March 2004 through August 2008.

Susan N. Story
Executive Vice President
Age 50
Elected in 2003. President and Chief Executive Officer of SCS since January 1, 2011. Previously served as President, Chief Executive Officer, and Director of Gulf Power from April 2003 through December 2010.

Anthony J. Topazi
Executive Vice President and Chief Operating Officer
Age 60
Elected in 2003. Executive Vice President and Chief Operating Officer since August 13, 2010. Previously served as President, Chief Executive Officer, and Director of Mississippi Power from January 2004 through August 12, 2010.

Christopher C. Womack
Executive Vice President
Age 52
Elected in 2008. Executive Vice President and President of External Affairs since January 1, 2009. Previously served as Executive Vice President of External Affairs of Georgia Power from March 2006 through December 2008 and Senior Vice President of Fossil and Hydro Generation and Senior Production Officer of Georgia Power from December 2001 to February 2006.

The officers of Southern Company were elected for a term running from the first meeting of the directors following the last annual meeting (May 26, 2010) for one year until the first board meeting after the next annual meeting or until their successors are elected and have qualified, except for Ms. Story, whose election was effective January 1, 2011, and Messrs. Beattie, and Topazi, whose elections were effective August 13, 2010. Mr. Fanning was elected President effective August 1, 2010 and Chairman, President, Chief Executive Officer, and Director effective December 1, 2010.

EXECUTIVE OFFICERS OF ALABAMA POWER

(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2010.

Charles D. McCrary
President, Chief Executive Officer, and Director
Age 59
Elected in 2001. President, Chief Executive Officer, and Director since October 2001; Executive Vice President of Southern Company since February 2002.

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
Age 51
Elected in 2010. Executive Vice President, Chief Financial Officer and Treasurer since August 13, 2010. Previously served as Vice President and Chief Financial Officer of Gulf Power from May 2008 to August 12, 2010 and as Vice President and Comptroller of Alabama Power from January 2005 to April 2008.

Zeke W. Smith
Executive Vice President
Age 51
Elected in 2010. Executive Vice President of External Affairs since November 8, 2010. Previously served as Vice President of Regulatory Services and Financial Planning from February 2005 to November 2010.

Steven R. Spencer
Executive Vice President
Age 55
Elected in 2001. Executive Vice President of the Customer Service Organization since February 1, 2008. Previously served as Executive Vice President of External Affairs from 2001 through January 2008.

Theodore J. McCullough
Senior Vice President and Senior Production Officer
Age 47
Elected in 2010. Senior Vice President and Senior Production Officer since June 30, 2010. Previously served as Vice President and Senior Production Officer of Gulf Power from September 2007 until June 2010, and Manager of Georgia Power's Plant Branch from December 2003 to August 2007.

The officers of Alabama Power were elected for a term running from the meeting of the directors held on April 23, 2010 for one year or until their successors are elected and have qualified, except for Messrs. Raymond, Smith, and McCullough, whose elections were effective August 13, 2010, November 8, 2010, and June 30, 2010, respectively.

EXECUTIVE OFFICERS OF GEORGIA POWER

(Identification of executive officers of Georgia Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2010.

W. Paul Bowers
President, Chief Executive Officer, and Director
Age 54
Elected in 2010. Chief Executive Officer, President, and Director since December 31, 2010 and Chief Operating Officer of Georgia Power from August 13, 2010 to December 31, 2010. He previously served as Executive Vice President and Chief Financial Officer of Southern Company from February 2008 to August 12, 2010. He also served as Executive Vice President of Southern Company from May 2007 to February 2008 and as President of Southern Company Generation, a business unit of Southern Company, and Executive Vice President of SCS from May 2001 through January 2008.

W. Craig Barrs
Executive Vice President
Age 53
Elected in 2008. Executive Vice President of External Affairs since January 2010. Previously served as Senior Vice President of External Affairs from January 2009 to January 2010, Vice President of Governmental and Regulatory Affairs from April 2008 to December 2008, Vice President of the Coastal Region from August 2006 to March 2008, and President and Chief Executive Officer of Savannah Electric and Power Company from January 2006 until its merger with and into Georgia Power which was completed in July 2006.

Mickey A. Brown
Executive Vice President
Age 63
Elected in 2001. Executive Vice President of the Customer Service Organization since January 2005.

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer, and Treasurer
Age 57
Elected in 2009. Executive Vice President, Chief Financial Officer, and Treasurer since April 2009. Previously served as Vice President of Internal Auditing at SCS from April 2008 to March 2009 and Vice President and Chief Financial Officer of Gulf Power from July 2001 to March 2008.

Joseph A. Miller
Executive Vice President
Age 49
Elected in 2009. Executive Vice President of Nuclear Development since May 2009. Also serves as Executive Vice President of Nuclear Development at Southern Nuclear since February 2006. Previously served as Vice President of Government Relations at SCS from May 1999 to January 2006.

Thomas P. Bishop
Senior Vice President, Chief Compliance Officer, and General Counsel
Age 50
Elected in 2008. Senior Vice President, Chief Compliance Officer, and General Counsel since September 2008. Previously served as Vice President and Associate General Counsel for SCS from July 2004 to September 2008.

Stan W. Connally
Senior Vice President and Chief Production Officer
Age 41
Elected in 2010. Senior Vice President and Chief Production Officer since August 1, 2010. Previously served as Manager of Alabama Power's Plant Barry from August 2007 through July 2010 and Manager of Mississippi Power's Plant Daniel from November 2004 through August 2007.

The officers of Georgia Power were elected for a term running from the meeting of the directors held on May 19, 2010 for one year or until their successors are elected and have qualified, except for Messrs. Bowers and Connally. Mr. Bowers was elected Chief Operating Officer effective August 13, 2010 and Chief Executive Officer, President, and Director effective December 31, 2010. Mr. Connally was elected effective August 1, 2010.

EXECUTIVE OFFICERS OF MISSISSIPPI POWER

(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2010.

Edward Day, VI
President, Chief Executive Officer, and Director
Age 50
Elected in 2010. President, Chief Executive Officer, and Director since August 13, 2010. Previously served as Executive Vice President for Engineering and Construction Services at Southern Company Generation, a business unit of Southern Company, from May 2003 to August 12, 2010.

Thomas O. Anderson, IV
Vice President
Age 51
Elected in 2009. Vice President of Generation Development since July 2009. Previously served as Project Director, Mississippi Power Generation Development from March 2008 to July 2009; Project Manager, Southern Power Generation from June 2007 to March 2008; and Generation Development Manager, SCS Generation Development from September 1998 to June 2007.

John W. Atherton
Vice President
Age 50
Elected in 2004. Vice President of External Affairs since January 2005.

Moses H. Feagin
Vice President, Treasurer, and
Chief Financial Officer
Age 46
Elected in 2010. Vice President, Treasurer, and Chief Financial Officer since August 13, 2010. Previously served as Vice President and Comptroller of Alabama Power from May 2008 to August 12, 2010, and Comptroller of Mississippi Power from March 2005 to May 2008.

Donald R. Horsley
Vice President
Age 56
Elected in 2006. Vice President of Customer Services Organization since April 2006. Previously served as Vice President of Transmission at Alabama Power from March 2005 to March 2006.

R. Allen Reaves
Vice President
Age 51
Elected in 2010. Vice President and Senior Production Officer since August 1, 2010. Previously served as Manager of Mississippi Power's Plant Daniel from September 2007 through July 2010 and Site Manager for Southern Power's Plant Franklin, from March 2006 to September 2007.

The officers of Mississippi Power were elected for a term running from the meeting of the directors held on April 8, 2010 for one year or until their successors are elected and have qualified, except for Messrs. Day and Feagin, whose elections were effective August 13, 2010, and Mr. Reaves, whose election was effective August 1, 2010.

PART II

Item 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(a)(1) The common stock of Southern Company is listed and traded on the New York Stock Exchange. The common stock is also traded on regional exchanges across the United States. The high and low stock prices as reported on the New York Stock Exchange for each quarter of the past two years were as follows:

	High	Low
2010		
First Quarter	$ 33.73	30.85
Second Quarter	35.45	32.04
Third Quarter	37.73	33.00
Fourth Quarter	38.62	37.10
2009		
First Quarter	$ 37.62	$26.48
Second Quarter	32.05	27.19
Third Quarter	32.67	30.27
Fourth Quarter	34.47	30.89

There is no market for the other registrants' common stock, all of which is owned by Southern Company.

(a)(2) Number of Southern Company's common stockholders of record at January 31, 2011: 159,733

Each of the other registrants have one common stockholder, Southern Company.

(a)(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors. The dividends on common stock declared by Southern Company and the traditional operating companies to their stockholder(s) for the past two years were as follows:

Registrant	Quarter	2010	2009
		(in thousands)	
Southern Company	First	$ 359,144	$ 326,780
	Second	375,865	343,446
	Third	378,939	348,702
	Fourth	382,440	350,538
Alabama Power	First	135,675	130,700
	Second	135,675	130,700
	Third	135,675	130,700
	Fourth	178,675	130,700
Georgia Power	First	205,000	184,725
	Second	205,000	184,725
	Third	205,000	184,725
	Fourth	205,000	184,725
Gulf Power	First	26,075	22,325
	Second	26,075	22,325
	Third	26,075	22,325
	Fourth	26,075	22,325
Mississippi Power	First	17,150	17,125
	Second	17,150	17,125
	Third	17,150	17,125
	Fourth	17,150	17,125

In 2010 and 2009, Southern Power paid dividends to Southern Company as follows:

Registrant	Quarter	2010	2009
		(in thousands)	
Southern Power	First	$26,775	$26,525
	Second	26,775	26,525
	Third	26,775	26,525
	Fourth	26,775	26,525

The dividend paid per share of Southern Company's common stock was 43.75¢ for the first quarter of 2010 and 45.50¢ for the second, third, and fourth quarters of 2010. In 2009, Southern Company paid a dividend per share of 42¢ in the first quarter of 2009 and 43.75¢ for the second, third, and fourth quarters of 2009.

The traditional operating companies and Southern Power can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Southern Power's credit facility and senior note indenture contain potential limitations on the payment of common stock dividends. At December 31, 2010, Southern Power was in compliance with the conditions of this credit facility and thus had no restrictions on its ability to pay common stock dividends. See Note 8 to the financial statements of Southern Company under "Common Stock Dividend Restrictions" and Note 6 to the financial statements of Southern Power under "Dividend Restrictions" in Item 8 herein for additional information regarding these restrictions.

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

Item 6. SELECTED FINANCIAL DATA

Southern Company. See "SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA," contained herein at pages II-103 and II-104.

Alabama Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-178 and II-179.

Georgia Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-258 and II-259.

Gulf Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-328 and II-329.

Mississippi Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-409 and II-410.

Southern Power. See "SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA," contained herein at page II-458.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Southern Company. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-11 through II-43.

Alabama Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-108 through II-132.

Georgia Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND

RESULTS OF OPERATIONS," contained herein at pages II-183 through II-210.

Gulf Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-263 through II-286.

Mississippi Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-333 through II-362.

Southern Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-414 through II-433.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See MANAGEMENT'S DISCUSSION AND ANALYSIS - FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each of the registrants in Item 7 herein and Note 1 of each of the registrant's financial statements under "Financial Instruments" in Item 8 herein. See also Note 10 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Note 9 to the financial statements of Gulf Power and Mississippi Power, and Note 8 to the financial statements of Southern Power in Item 8 herein.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO 2010 FINANCIAL STATEMENTS

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls And Procedures.

As of the end of the period covered by this annual report, Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Sections 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

Internal Control Over Financial Reporting.

(a) Management's Annual Report on Internal Control Over Financial Reporting.

Southern Company's Management's Report on Internal Control Over Financial Reporting is included on page II-9 of this Form 10-K.

Alabama Power's Management's Report on Internal Control Over Financial Reporting is included on page II-106 of this Form 10-K.

Georgia Power's Management's Report on Internal Control Over Financial Reporting is included on page II-181 of this Form 10-K.

Gulf Power's Management's Report on Internal Control Over Financial Reporting is included on page II-261 of this Form 10-K.

Mississippi Power's Management's Report on Internal Control Over Financial Reporting is included on page II-331 of this Form 10-K.

Southern Power's Management's Report on Internal Control Over Financial Reporting is included on page II-412 of this Form 10-K.

(b) Attestation Report of the Registered Public Accounting Firm.

The report of Deloitte & Touche LLP, Southern Company's independent registered public accounting firm, regarding Southern Company's internal control over financial reporting is included on page II-10 of this Form 10-K.

Not applicable to Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power because these companies are not accelerated filers.

(c) Changes in internal controls.

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the fourth quarter 2010 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting.

Item 9B. OTHER INFORMATION

Southern Company

Southern Company, SCS, and Thomas A. Fanning entered into an amendment to Mr. Fanning's Amended and Restated Change in Control Agreement, which terminates such agreement, effective February 22, 2011. Following the termination, Mr. Fanning is a participant in the Amended and Restated Senior Executive Change in Control Severance Plan. The Amendment is filed herewith as Exhibit 10(a)14.

Southern Company, SCS, and W. Paul Bowers entered into an amendment to Mr. Bowers' Amended and Restated Change in Control Agreement, which terminates such agreement, effective February 22, 2011. Following the termination, Mr. Bowers is a participant in the Amended and Restated Senior Executive Change in Control Severance Plan. The amendment is filed herewith as Exhibit 10(a)18.

Southern Company, Alabama Power, and Charles D. McCrary entered into an amendment to Mr. McCrary's Amended and Restated Change in Control Agreement, which terminates such agreement, effective February 22, 2011. Following the termination, Mr. McCrary is a participant in the Amended and Restated Senior Executive Change in Control Severance Plan. The amendment is filed herewith as Exhibit 10(a)8.

Effective February 23, 2011, The Southern Company Senior Executive Change in Control Severance Plan (Plan) was amended to reduce the severance benefit provided to all executive officers of Southern Company, except the Chief Executive Officer, from three times salary plus annual performance-based compensation target opportunity to two times that amount. The amendment also provides that any severance payment under the Plan shall not exceed three times a participant's base amount as such term is defined under Section 280G of the Code. The amendment to the Plan is filed herewith as Exhibit 10(a)16.

On February 22, 2011, Georgia Power entered into a Separation and Release Agreement with Michael D. Garrett in connection with his retirement from Georgia Power. Under the agreement, Georgia Power will pay Mr. Garrett a severance payment of $1,000,000.00. The agreement contains standard non-compete and confidentiality terms and a legal release. The agreement is filed herewith as Exhibit 10(a)9.

THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Southern Company and Subsidiary Companies 2010 Annual Report

Southern Company's management 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 Southern 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 Southern Company's internal control over financial reporting was effective as of December 31, 2010.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Southern Company's financial statements, has issued an attestation report on the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2010. Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

Thomas A. Fanning
Chairman, President, and Chief Executive Officer

Art P. Beattie
Executive Vice President and Chief Financial Officer

February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Southern Company

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Southern Company and Subsidiary Companies (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule of the Company listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and the financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page II-9). Our responsibility is to express an opinion on these financial statements and the financial statement schedule and an opinion on the Company's internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements (pages II-44 to II-101) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2010 and 2009, and the results of their operations and their 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. Also, in our opinion, the financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Atlanta, Georgia
February 25, 2011

OVERVIEW

Business Activities

The primary business of Southern Company (the Company) is electricity sales in the Southeast by the traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – and Southern Power. The four traditional operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market.

Many factors affect the opportunities, challenges, and risks of Southern Company's electricity business. These factors include the traditional operating companies' 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. Each of the traditional operating companies has various regulatory mechanisms that operate to address cost recovery. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Another major factor is the profitability of the competitive market-based wholesale generating business and federal regulatory policy. Southern Power continues to execute its strategy through a combination of acquiring and constructing new power plants and by entering into power purchase agreements (PPAs) with investor owned utilities, independent power producers, municipalities, and electric cooperatives.

Southern Company's other business activities include investments in leveraged lease projects, renewable energy projects, and telecommunications. Management continues to evaluate the contribution of each of these activities to total shareholder return and may pursue acquisitions and dispositions accordingly.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to more than four million customers, Southern Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and earnings per share (EPS). Southern Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The fossil/hydro 2010 Peak Season EFOR of 1.67% 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.

Southern 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 - fossil/hydro	5.06% or less	1.67%
Basic EPS	$2.30 – $2.36	$2.37

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2010 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was $1.98 billion in 2010, an increase of $332 million from the prior year. This increase was primarily the result of increases in revenues due to colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010, a litigation settlement agreement with MC Asset Recovery, LLC (MC Asset Recovery) in the first quarter 2009, increased amortization of the regulatory liability related to other cost of removal obligations at Georgia Power as authorized by the Georgia Public Service Commission (PSC), revenues associated with increases in rates under Alabama Power's rate stabilization and equalization plan (Rate RSE) and rate certificated new plant environmental (Rate CNP Environmental) that took effect in January 2010, and increases in sales primarily in the industrial sector. The 2010 increase was partially offset by increases in operations and maintenance expenses, which include an additional accrual to Alabama Power's natural disaster reserve (NDR), a gain in 2009 on the early termination of two leveraged lease investments, and an increase in depreciation on additional plant in service related to environmental, distribution, and transmission projects. Net income after dividends on preferred and preference stock of subsidiaries was $1.64 billion in 2009 and $1.74 billion in 2008.

Basic EPS was $2.37 in 2010, $2.07 in 2009, and $2.26 in 2008. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.36 in 2010, $2.06 in 2009, and $2.25 in 2008. EPS for 2010 was negatively impacted by $0.12 per share as a result of an increase in the average shares outstanding.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $1.8025 in 2010, $1.7325 in 2009, and $1.6625 in 2008. In January 2011, Southern Company declared a quarterly dividend of 45.50 cents per share. This is the 253rd consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. The Company targets a dividend payout ratio of approximately 70% of net income. For 2010, the actual payout ratio was 76%.

RESULTS OF OPERATIONS

Electricity Business

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers in the Southeast. A condensed statement of income for the electricity business follows:

	Amount	**Increase (Decrease) from Prior Year**		
	2010	**2010**	2009	2008
		(in millions)		
Electric operating revenues	**$ 17,374**	**$ 1,732**	$ (1,358)	$ 1,860
Fuel	**6,699**	**747**	(865)	973
Purchased power	**563**	**89**	(341)	300
Other operations and maintenance	**3,907**	**505**	(183)	111
Depreciation and amortization	**1,494**	**19**	62	199
Taxes other than income taxes	**867**	**51**	22	56
Total electric operating expenses	**13,530**	**1,411**	(1,305)	1,639
Operating income	**3,844**	**321**	(53)	221
Other income (expense), net	**159**	**(41)**	53	26
Interest expense, net of amounts capitalized	**833**	**(2)**	61	10
Income taxes	**1,116**	**128**	(49)	87
Net income	**2,054**	**154**	(12)	150
Dividends on preferred and preference stock of subsidiaries	**65**	**-**	-	17
Net income after dividends on preferred and preference stock of subsidiaries	**$ 1,989**	**$ 154**	$ (12)	$ 133

Electric Operating Revenues

Details of electric operating revenues were as follows:

	Amount		
	2010	2009	2008
		(in millions)	
Retail – prior year	**$ 13,307**	$ 14,055	$ 12,639
Estimated change in –			
Rates and pricing	**384**	144	668
Sales growth (decline)	**32**	(208)	-
Weather	**439**	(21)	(106)
Fuel and other cost recovery	**629**	(663)	854
Retail – current year	**14,791**	13,307	14,055
Wholesale revenues	**1,994**	1,802	2,400
Other electric operating revenues	**589**	533	545
Electric operating revenues	**$ 17,374**	$ 15,642	$ 17,000
Percent change	**11.1%**	(8.0%)	12.3%

Retail revenues increased $1.5 billion, decreased $748 million, and increased $1.4 billion in 2010, 2009, and 2008, respectively. The significant factors driving these changes are shown in the preceding table. The increase in rates and pricing in 2010 was primarily due to Rate RSE and Rate CNP Environmental increases at Alabama Power and the recovery of environmental costs at Gulf Power. The 2009 increase in rates and pricing when compared to the prior year was primarily due to an increase in revenues from customer charges at Alabama Power and increased environmental compliance cost recovery (ECCR) revenues at Georgia Power in accordance with its retail rate plan for the years 2008 through 2010 (2007 Retail Rate Plan), partially offset by a decrease in revenues from market-response rates to large commercial and industrial customers at Georgia Power. The 2008 increase in rates and pricing when compared to the prior year was primarily due to Alabama Power's increase under its Rate RSE, as ordered by the Alabama PSC, and Georgia Power's increase under the 2007 Retail Rate Plan, as ordered by the Georgia PSC. Also contributing to the 2008 increase was an increase in revenues from market-response rates to large commercial and industrial customers. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. The traditional operating companies may also have one or more regulatory mechanisms to recover other costs such as environmental, storm damage, new plants, and PPAs.

Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives, unit power sales contracts, and short-term opportunity sales. Wholesale revenues from PPAs and unit power sales contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy revenues will vary depending on the market cost of available energy compared to the cost of the Company's system-owned generation, demand for energy within the Company's service territory, and the availability of the Company's system generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

In 2010, wholesale revenues increased $192 million primarily due to higher capacity and energy revenues under existing PPAs and new PPAs at Southern Power that began in January, June, and July 2010, as well as increased energy sales that were not covered by PPAs at Southern Power due to more favorable weather. This increase was partially offset by the expiration of long-term unit power sales contracts in May 2010 at Alabama Power and the capacity subject to those contracts being made available for retail service starting in June 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Rate CNP" herein for additional information regarding the termination of certain unit power sales contracts in 2010.

In 2009, wholesale revenues decreased $598 million. Wholesale fuel revenues, which are generally offset by wholesale fuel expenses and do not affect net income, decreased $603 million in 2009. Excluding wholesale fuel revenues, wholesale revenues increased $5 million primarily due to additional revenues associated with a new PPA at Southern Power's Plant Franklin Unit 3 which began in January 2009, partially offset by fewer short-term opportunity sales due to lower gas prices and reduced margins on short-term opportunity sales.

In 2008, wholesale revenues increased $412 million primarily as a result of a 21.8% increase in the average cost of fuel per net kilowatt-hour (KWH) generated, as well as revenues resulting from new and existing PPAs and revenues derived from contracts for Southern Power's Plant Oleander Unit 5 and Plant Franklin Unit 3 placed in operation in December 2007 and June 2008, respectively. The 2008 increase was partially offset by a decrease in short-term opportunity sales and weather-related generation load reductions.

Revenues associated with PPAs and opportunity sales were as follows:

	2010	2009	2008
		(in millions)	
Other power sales –			
Capacity and other	**$ 684**	$ 575	$ 538
Energy	**1,034**	735	1,319
Total	**$ 1,718**	$ 1,310	$ 1,857

KWH sales under unit power sales contracts decreased 55.0%, 7.5%, and 2.1% in 2010, 2009, and 2008, respectively. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Rate CNP" herein for additional information regarding the termination of certain unit power sales contracts in 2010, which resulted in a decrease in capacity and energy revenues. In addition, fluctuations in oil and natural gas prices, which are the primary fuel sources for unit power sales contracts, influence changes in energy sales. However, because the energy is generally sold at variable cost, fluctuations in energy sales have a minimal effect on earnings. The capacity and energy components of the unit power sales contracts were as follows:

	2010	2009	2008
		(in millions)	
Unit power sales –			
Capacity	**$ 136**	$ 225	$ 223
Energy	**140**	267	320
Total	**$ 276**	$ 492	$ 543

Other Electric Revenues

Other electric revenues increased $56 million, decreased $12 million, and increased $32 million in 2010, 2009, and 2008, respectively. Other electric revenues increased in 2010 primarily as a result of a $38 million increase in transmission revenues, a $4 million increase in rents from electric property, a $4 million increase in outdoor lighting revenues, and a $4 million increase in late fees. The 2009 decrease in other electric revenues was not material when compared to 2008. The 2008 increase in other electric revenues was not material when compared to 2007.

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 billions)						
Residential	**57.8**	**11.8%**	(1.1)%	(2.0)%	**0.2%**	(0.7)%	0.0%
Commercial	**55.5**	**3.7**	(1.7)	(0.4)	**(0.6)**	(1.2)	1.0
Industrial	**50.0**	**7.7**	(11.8)	(3.7)	**7.1**	(11.7)	(3.5)
Other	**0.9**	**(1.0)**	2.0	(2.9)	**(1.5)**	2.2	(2.7)
Total retail	**164.2**	**7.6**	(4.8)	(2.1)	**2.0%**	(4.5)%	(0.9)%
Wholesale	**32.6**	**(2.8)**	(14.9)	(3.4)			
Total energy sales	**196.8**	**5.7%**	(6.8)%	(2.3)%			

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales increased 11.6 billion KWHs in 2010. This increase was primarily the result of colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010, increased industrial KWH sales, and customer growth of 0.3%. Increased demand in the primary metals, chemicals, and transportations sectors were the main contributors to the increase in industrial KWH sales. Retail energy sales decreased 7.7 billion KWHs in 2009 primarily as a result of lower usage by industrial customers due to the recessionary economy. Reduced demand in the primary metal, chemical, and textile sectors, as well as the stone, clay, and glass sector, contributed most significantly to the decrease in industrial KWH sales. Unfavorable weather also contributed to lower KWH sales across all customer classes. The number of customers in 2009 was flat compared to 2008. Retail energy sales in 2008 decreased 3.4 billion KWHs as a result of a 1.4% decrease in electricity usage mainly due to a slowing economy that worsened during the fourth quarter. The 2008 decrease in residential sales resulted primarily from lower home occupancy rates in Southern Company's service area when compared to 2007. Throughout the year, reduced demand in the textile sector, the lumber sector, and the stone, clay, and glass sector contributed to the decrease in 2008 industrial sales. Additional weakness in the fourth quarter 2008 affected all major industrial segments. Significantly less favorable weather in 2008 when compared to 2007 also contributed to the 2008 decrease in retail energy sales. These decreases were partially offset by customer growth of 0.6%.

Wholesale energy sales decreased by 0.9 billion KWHs in 2010, decreased by 5.9 billion KWHs in 2009, and decreased by 1.4 billion KWHs in 2008. The decrease in wholesale energy sales in 2010 was primarily related to the expiration of long-term unit power sales contracts in May 2010 at Alabama Power and the capacity subject to those contracts being made available for retail service starting in June 2010. This decrease was partially offset by increased energy sales under existing PPAs and new PPAs at Southern Power that began in January, June, and July 2010, as well as sales that were not covered by PPAs at Southern Power primarily due to more favorable weather in 2010 compared to 2009. The decrease in wholesale energy sales in 2009 was primarily related to fewer short-term opportunity sales driven by lower gas prices and fewer uncontracted generating units at Southern Power available to sell electricity on the wholesale market. The decrease in wholesale energy sales in 2008 was primarily related to longer planned maintenance outages at a fossil unit in 2008 as compared to 2007 which reduced the availability of this unit for wholesale sales. Lower short-term opportunity sales primarily related to higher coal prices also contributed to the 2008 decrease. These decreases were partially offset by Plant Oleander Unit 5 and Plant Franklin Unit 3 at Southern Power being placed in operation in December 2007 and June 2008, respectively.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the electric utilities. 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 electric utilities purchase a portion of their electricity needs from the wholesale market. Details of electricity generated and purchased by the electric utilities were as follows:

	2010	2009	2008
Total generation *(billions of KWHs)*	**196**	187	198
Total purchased power *(billions of KWHs)*	**10**	8	11
Sources of generation *(percent)* –			
Coal	**58**	57	68
Nuclear	**15**	16	15
Gas	**25**	23	16
Hydro	**2**	4	1
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.93**	3.70	3.27
Nuclear	**0.63**	0.55	0.50
Gas	**4.27**	4.58	7.58
Average cost of fuel, generated *(cents per net KWH)**	**3.50**	3.38	3.52
Average cost of purchased power *(cents per net KWH)*	**6.98**	6.37	7.85

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

In 2010, fuel and purchased power expenses were $7.3 billion, an increase of $836 million or 13.0% above 2009 costs. This increase was primarily the result of a $538 million increase in the amount of total KWHs generated and purchased due primarily to increased customer demand. Also contributing to this increase was a $298 million increase in the average cost per KWH generated and purchased due primarily to a 3.6% increase in the cost per KWH generated and a 9.6% increase in the cost per KWH purchased.

In 2009, fuel and purchased power expenses were $6.4 billion, a decrease of $1.2 billion or 15.8% below 2008 costs. This decrease was primarily the result of an $839 million decrease related to the total KWHs generated and purchased due primarily to lower customer demand. Also contributing to this decrease was a $367 million reduction in the average cost of fuel and purchased power resulting primarily from a 39.6% decrease in the cost of gas per KWH generated.

In 2008, fuel and purchased power expenses were $7.6 billion, an increase of $1.3 billion or 20.0% above 2007 costs. This increase was primarily the result of a $1.3 billion net increase in the average cost of fuel and purchased power partially resulting from a 25.3% increase in the cost of coal per net KWH generated and a 14.2% increase in the cost of gas per net KWH generated.

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. Uranium prices remained relatively constant during the early portion of 2010 but rose steadily during the second half of the year. At year end, uranium prices remained well below the highs set during 2007. Worldwide uranium production levels increased in 2010; however, secondary supplies and inventories were still required to meet worldwide reactor demand.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the traditional operating companies' fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information. Likewise, Southern Power's PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses were $3.9 billion, $3.4 billion, and $3.6 billion, increasing $505 million, decreasing $183 million, and increasing $111 million in 2010, 2009, and 2008, respectively. Discussion of significant variances for components of other operations and maintenance expenses follows.

Other production expenses at fossil, hydro, and nuclear plants increased $277 million, decreased $70 million, and increased $63 million in 2010, 2009, and 2008, respectively. Production expenses fluctuate from year to year due to variations in outage schedules and changes in the cost of labor and materials. Other production expenses increased in 2010 mainly due to a $178 million increase in outage and maintenance costs and an $86 million increase in commodity and labor costs, reflecting a return to more normal spending levels when compared to 2009. Also contributing to this increase was an $18 million increase in maintenance costs related to additional equipment placed in service. Partially offsetting the 2010 increase was a $5 million loss recognized in 2009 on the transfer of Southern Power's Plant Desoto. Other production expenses decreased in 2009 mainly due to a $104 million decrease related to less planned spending on outages and maintenance, as well as other cost containment activities, which were the results of efforts to offset the effects of the recessionary economy. The 2009 decrease was partially offset by a $6 million increase related to new facilities, a $5 million loss on the transfer of Southern Power's Plant Desoto in 2009, a $6 million gain recognized in 2008 by Southern Power on the sale of an undeveloped tract of land to the Orlando Utilities Commission (OUC), and a $17 million increase in nuclear refueling costs. Other production expenses increased in 2008 primarily due to a $64 million increase related to expenses incurred for maintenance outages at generating units and a $30 million increase related to labor and materials expenses, partially offset by a $15 million decrease in nuclear refueling costs. The 2008 increase was also partially offset by a $24 million decrease related to new facilities, mainly lower costs associated with the 2007 write-off of Southern Power's integrated coal gasification combined cycle (IGCC) project with the OUC. See Note 1 to the financial statements under "Property, Plant, and Equipment" for additional information regarding nuclear refueling costs.

Transmission and distribution expenses increased $143 million, decreased $41 million, and increased $4 million in 2010, 2009, and 2008, respectively. Transmission and distribution expenses fluctuate from year to year due to variations in maintenance schedules and normal changes in the cost of labor and materials. Transmission and distribution expenses increased in 2010 primarily due to increased spending on line clearing and other maintenance costs, reflecting a return to more normal spending levels, as well as an additional accrual to Alabama Power's NDR. Transmission and distribution expenses decreased in 2009 primarily related to lower planned spending, as well as other cost containment activities, partially offset by an additional accrual to Alabama Power's NDR. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Natural Disaster Reserve" herein for additional information. The 2008 increase in transmission and distribution expenses was not material when compared to the prior year.

Customer sales and service expenses increased $18 million, decreased $42 million, and increased $32 million in 2010, 2009, and 2008, respectively. Customer sales and service expenses increased in 2010 primarily as a result of an $8 million increase in sales expenses, a $13 million increase in customer service expense, a $10 million increase in records and collection, and a $3 million increase in uncollectible accounts expense. Partially offsetting this increase was a $7 million decrease in meter reading expenses and a $9 million decrease in other energy services. Customer sales and service expenses decreased in 2009 primarily as a result of a $12 million decrease in customer service expenses, an $8 million decrease in meter reading expenses, a $10 million decrease in sales expenses, and a $7 million decrease in customer records related expenses. The 2008 increase in customer sales and service expenses was primarily a result of an increase in customer service expenses, including a $13 million increase in uncollectible accounts expense, a $9 million increase in meter reading expenses, and an $8 million increase for customer records and collections.

Administrative and general expenses increased $67 million, decreased $30 million, and increased $12 million in 2010, 2009, and 2008, respectively. Administrative and general expenses increased in 2010 primarily as a result of cost containment activities in 2009 which were taken to offset the effects of the recessionary economy. The 2008 increase in administrative and general expenses was not material when compared to 2007.

Depreciation and Amortization

Depreciation and amortization increased $19 million in 2010 primarily as the result of additional depreciation on plant in service related to environmental, transmission, and distribution projects, as well as additional depreciation at Southern Power. This increase was largely offset by a $133 million increase in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power as authorized by the Georgia PSC. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power– Retail Rate Plans" for additional information regarding Georgia Power's cost of removal amortization.

Depreciation and amortization increased $62 million in 2009 primarily as a result of an increase in plant in service related to environmental, transmission, and distribution projects mainly at Alabama Power and Georgia Power and the completion of Southern Power's Plant Franklin Unit 3, as well as an increase in depreciation rates at Southern Power. Partially offsetting the 2009 increase was a decrease associated with the amortization of the regulatory liability related to the cost of removal obligations as authorized by the Georgia PSC.

Depreciation and amortization increased $199 million in 2008 primarily as a result of an increase in plant in service related to environmental, transmission, and distribution projects mainly at Alabama Power and Georgia Power and generation projects at Georgia Power. An increase in depreciation rates at Georgia Power and Southern Power also contributed to the 2008 increase, as well as the expiration of a rate order previously allowing Georgia Power to levelize certain purchased power capacity costs and the completion of Southern Power's Plant Oleander Unit 5 in December 2007 and Plant Franklin Unit 3 in June 2008.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $51 million in 2010 primarily due to higher municipal franchise fees at Georgia Power as a result of increased retail revenues, increases in state and municipal public utility license tax bases at Alabama Power, increases in gross receipts and franchise fees at Gulf Power, increases in ad valorem taxes, and increases in payroll taxes. Taxes other than income taxes increased $22 million in 2009 primarily as a result of increases in the bases of state and municipal public utility license taxes at Alabama Power and an increase in franchise fees at Gulf Power. Increases in franchise fees are associated with increases in revenues from energy sales. Taxes other than income taxes increased $56 million in 2008 primarily as a result of increases in franchise fees and municipal gross receipt taxes associated with increases in revenues from energy sales, as well as increases in property taxes associated with property tax actualizations and additional plant in service.

Other Income (Expense), Net

Other income (expense), net decreased $41 million in 2010 primarily due to a decrease in allowance for funds used during construction (AFUDC) equity, mainly due to the completion of environmental projects at Alabama Power and Gulf Power, and a $13 million profit recognized in 2009 at Southern Power related to a construction contract with the OUC. The 2010 decrease was partially offset by increases in AFUDC equity related to the increase in construction of three new combined cycle units and two new nuclear generating units at Georgia Power. Other income (expense), net increased $53 million in 2009 primarily due to an increase in AFUDC equity as a result of environmental projects at Alabama Power and Gulf Power and additional investments in transmission and distribution projects at Alabama Power. In addition, during 2009, Southern Power recognized a $13 million profit under a construction contract with the OUC whereby Southern Power provided engineering, procurement, and construction services to build a combined cycle unit. Other income (expense), net increased $26 million in 2008 primarily as a result of an increase in AFUDC equity related to additional investments in environmental equipment at generating plants at Alabama Power, Georgia Power, and Gulf Power, as well as additional investments in transmission and distribution projects mainly at Alabama Power and Georgia Power.

Interest Expense, Net of Amounts Capitalized

Total interest charges and other financing costs decreased $2 million in 2010 primarily due to an $18 million decrease related to lower average interest rates on existing variable rate debt, an $11 million decrease in other interest costs, and a $2 million increase in capitalized interest as compared to 2009. The 2010 decrease was largely offset by a $29 million increase associated with $1.0 billion in additional debt outstanding at December 31, 2010 compared to December 31, 2009.

Total interest charges and other financing costs increased by $61 million in 2009 primarily as a result of a $100 million increase associated with $1.4 billion in additional debt outstanding at December 31, 2009 compared to December 31, 2008. Also contributing to the 2009 increase was $16 million in other interest costs. The 2009 increase was partially offset by $42 million related to lower average interest rates on existing variable rate debt and $13 million of additional capitalized interest as compared to 2008.

Total interest charges and other financing costs increased by $10 million in 2008 primarily as a result of a $65 million increase associated with $1.8 billion in additional debt outstanding at December 31, 2008 compared to December 31, 2007. Also contributing to the 2008 increase was $5 million in other interest costs. The 2008 increase was partially offset by $55 million related to lower average interest rates on existing variable rate debt and $7 million of additional capitalized interest as compared to 2007.

Income Taxes

Income taxes increased $128 million in 2010 primarily due to higher pre-tax earnings as compared to 2009, a decrease in the Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 199 production activities deduction, and an increase in Alabama state taxes due to a decrease in the state deduction for federal income taxes paid. Partially offsetting this increase were state tax credits at Georgia Power and tax benefits associated with the construction of a biomass facility at Southern Power. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Income taxes decreased $49 million in 2009 primarily due to lower pre-tax earnings as compared to 2008, an increase in AFUDC equity, which is not taxable, and an increase in the federal production activities deduction.

Income taxes increased $87 million in 2008 primarily due to higher pre-tax earnings as compared to 2007 and a 2007 deduction for a Georgia Power land donation. The 2008 increase was partially offset by an increase in AFUDC equity, which is not taxable.

Dividends on Preferred and Preference Stock of Subsidiaries

In both 2010 and 2009, dividends on preferred and preference stock of subsidiaries were flat compared to the applicable prior year.

Dividends on preferred and preference stock of subsidiaries increased $17 million in 2008 primarily as a result of issuances of $320 million and $150 million of preference stock in the third and fourth quarters of 2007, respectively, partially offset by the redemption of $125 million of preferred stock in January 2008.

Other Business Activities

Southern Company's other business activities include the parent company (which does not allocate operating expenses to business units), investments in leveraged lease projects, and telecommunications. These businesses are classified in general categories and may comprise one or more of the following subsidiaries: Southern Company Holdings invests in various projects, including leveraged lease projects; and 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.

A condensed statement of income for Southern Company's other business activities follows:

	Amount	Increase (Decrease) from Prior Year		
	2010	**2010**	2009	2008
		(in millions)		
Operating revenues	**$ 82**	**$ (19)**	$ (26)	$ (86)
Other operations and maintenance	**103**	**(22)**	(40)	(44)
MC Asset Recovery litigation settlement	**-**	**(202)**	202	-
Depreciation and amortization	**19**	**(8)**	(2)	(1)
Taxes other than income taxes	**2**	**-**	(1)	-
Total operating expenses	**124**	**(232)**	159	(45)
Operating income (loss)	**(42)**	**213**	(185)	(41)
Equity in income (losses) of unconsolidated subsidiaries	**(2)**	**(1)**	(11)	35
Leveraged lease income (losses)	**18**	**(22)**	125	(125)
Other income (expense), net	**(16)**	**(19)**	(8)	(31)
Interest expense	**62**	**(8)**	(22)	(30)
Income taxes	**(90)**	**1**	30	(7)
Net income (loss)	**$ (14)**	**$ 178**	$ (87)	$(125)

Operating Revenues

Southern Company's non-electric operating revenues from these other businesses decreased $19 million in 2010 primarily as a result of a decrease in revenues at SouthernLINC Wireless related to lower average revenue per subscriber and fewer subscribers due to increased competition in the industry. The $26 million decrease in 2009 primarily resulted from a $25 million decrease in revenues at SouthernLINC Wireless related to lower average revenue per subscriber and fewer subscribers due to increased competition in the industry. The $86 million decrease in 2008 primarily resulted from a $60 million decrease associated with Southern Company terminating its investment in synthetic fuel projects at December 31, 2007 and a $21 million decrease in revenues at SouthernLINC Wireless related to lower average revenue per subscriber and fewer subscribers due to increased competition in the industry. Also contributing to the 2008 decrease was a $5 million decrease in revenues from Southern Company's energy-related services business.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other businesses decreased $22 million in 2010 primarily as a result of lower administrative and general expenses for these other businesses. Other operations and maintenance expenses decreased $40 million in 2009 primarily as a result of a $15 million decrease in salary and wages, advertising, equipment, and network costs at SouthernLINC Wireless; a $10 million decrease in expenses associated with leveraged lease litigation costs; and a $6 million decrease in parent company expenses associated with the MC Asset Recovery litigation. Other operations and maintenance expenses decreased $44 million in 2008 primarily as a result of $11 million of lower coal expenses related to Southern Company terminating its investment in synthetic fuel projects at December 31, 2007; $9 million of lower sales expenses at SouthernLINC Wireless related to lower sales volume; and $5 million of lower parent company expenses related to advertising, litigation, and property insurance costs.

MC Asset Recovery Litigation Settlement

In March 2009, Southern Company entered into a litigation settlement agreement with MC Asset Recovery which resulted in a charge of $202 million and required MC Asset Recovery to release Southern Company and certain other designated avoidance actions assigned to MC Asset Recovery in connection with Mirant's plan of reorganization, as well as to release all actions against current or former officers and directors of Mirant and Southern Company that had or could have been filed. Pursuant to the settlement, Southern Company recorded a charge in the first quarter 2009 of $202 million, which was paid in the second quarter 2009. The settlement has been completed and resolves all claims by MC Asset Recovery against Southern Company. In June 2009, the case was dismissed with prejudice.

Equity in Income (Losses) of Unconsolidated Subsidiaries

Equity in income (losses) of unconsolidated subsidiaries for 2010 was flat when compared to the prior year. Equity in income (losses) of unconsolidated subsidiaries decreased $11 million in 2009 as a result of an $11 million gain recognized in 2008 related to the dissolution of a partnership that was associated with synthetic fuel production facilities. Equity in income (losses) of unconsolidated subsidiaries increased $35 million in 2008 primarily as a result of Southern Company terminating its investment in synthetic fuel projects at December 31, 2007.

Leveraged Lease Income (Losses)

Southern Company has several leveraged lease agreements which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Leveraged lease income (losses) decreased $22 million in 2010 primarily as a result of a $26 million gain recorded in 2009 associated with the early termination of two international leveraged lease investments, the proceeds from which were required to extinguish all debt related to the leveraged lease investments, and a portion of which had make-whole redemption provisions. This resulted in a $17 million loss in 2009, partially offsetting the gain. In addition, leveraged lease income decreased $6 million in 2010 primarily due to lease income no longer being recognized on the terminated leveraged lease investments. Leveraged lease income (losses) increased $125 million in 2009 primarily as a result of the application in 2008 of certain accounting standards related to leveraged leases, as well as a $26 million gain recorded in the second quarter 2009 associated with the early termination of two international leveraged lease investments. The proceeds from the termination were required to be used to extinguish all debt related to leveraged lease investments, a portion of which had make-whole redemption provisions. This resulted in a $17 million loss and partially offset the 2009 increase. Leveraged lease income (losses) decreased $125 million in 2008 as a result of Southern Company's decision to participate in a settlement with the Internal Revenue Service (IRS) related to deductions for several sale-in-lease-out transactions and the resulting application of certain accounting standards related to leveraged leases.

Other Income (Expense), Net

Other income (expense), net for these other businesses decreased $19 million in 2010 primarily due to charitable contributions made by the parent company. The 2009 change in other income (expense), net when compared to the prior year was not material. Other income (expense), net decreased $31 million in 2008 primarily as a result of the 2007 gain on a derivative transaction in the synthetic fuel business which settled on December 31, 2007.

Interest Expense

Total interest charges and other financing costs for these other businesses decreased $8 million in 2010 primarily due to lower average interest rates on existing variable rate debt. Total interest charges and other financing costs decreased $22 million in 2009 primarily as a result of $26 million associated with lower average interest rates on existing variable rate debt and a $2 million decrease attributed to other interest charges. The 2009 decrease was partially offset by a $4 million increase associated with $63 million in additional debt outstanding at December 31, 2009 compared to December 31, 2008. Total interest charges and other financing costs decreased $30 million in 2008 primarily as a result of $29 million associated with lower average interest rates on existing variable rate debt and a $4 million decrease attributed to lower interest rates associated with new debt issued to replace maturing securities. At December 31, 2008, these other businesses had $92 million in additional debt outstanding compared to December 31, 2007. The 2008 decrease was partially offset by a $5 million increase in other interest costs.

Income Taxes

The 2010 increase in income taxes for these other businesses was not material when compared to the prior year. Income taxes increased $30 million in 2009 excluding the effects of the $202 million charge resulting from the litigation settlement with MC Asset Recovery in the first quarter 2009. The 2009 increase was primarily due to the application in 2008 of certain accounting standards related to leveraged leases and income taxes. Partially offsetting this increase was lower tax expense associated with the early termination of two international leveraged lease investments and the extinguishment of the associated debt discussed previously under "Leveraged Lease Income (Losses)." Income taxes decreased $7 million in 2008 primarily as a result of leveraged lease losses discussed previously under "Leveraged Lease Income (Losses)," partially offset by a $36 million decrease in net synthetic fuel tax credits as a result of Southern Company terminating its investment in synthetic fuel projects at December 31, 2007. See Note 5 to the financial statements under "Effective Tax Rate" for further information.

Effects of Inflation

The traditional operating companies are 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. Southern Power is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on Southern Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The four traditional operating companies operate as vertically integrated utilities providing electricity to customers within their service areas in the Southeastern U.S. Prices for electricity provided to retail customers are set by state PSCs under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the Federal Energy Regulatory Commission (FERC). Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Southern Power continues to focus on long-term capacity contracts, optimized by limited energy trading activities. 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 Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Company's primary business of selling electricity. These factors include the traditional operating companies' 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. Other major factors include profitability of the competitive wholesale supply business and federal regulatory policy. Future earnings for the electricity business 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 and other wholesale customers, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the service area. In addition, the level of future earnings for the wholesale supply business also depends on numerous factors including creditworthiness of customers, total generating capacity available in the Southeast, future acquisitions and construction of generating facilities, and the successful remarketing of capacity as current contracts expire. Changes in economic conditions impact sales for the traditional operating companies and Southern Power, 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.

In 2010, Southern Company system generating capacity increased 30 megawatts due to the completion of a solar photovoltaic plant near Cimarron, New Mexico. In general, Southern Company has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities or to meet requirements of Southern Company's regulated retail markets, both of which are optimized by limited energy trading activities. See FUTURE EARNINGS POTENTIAL – "Construction Program" herein and Note 7 to the financial statements for additional information.

As part of its ongoing effort to adapt to changing market conditions, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company.

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 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. 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 facilities co-owned by Mississippi Power and Gulf Power. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The EPA concurrently issued notices of violation to Gulf Power and Mississippi Power relating to Gulf Power's Plant Crist and Mississippi Power's Plant Watson. In early 2000, the EPA filed a motion to amend its complaint to add Gulf Power and Mississippi Power as defendants based on the allegations in the notices of violation. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not re-filed. The original action, now solely against Georgia Power, has been administratively closed since the spring of 2001, and the case has not been reopened. The separate action against Alabama Power is ongoing.

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, including the claim relating to a facility co-owned by Mississippi Power. 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.

Southern Company believes that the traditional operating companies 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 electric utilities' 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 electric utilities had invested approximately $8.1 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $500 million, $1.3 billion, and $1.6 billion for 2010, 2009, and 2008, respectively. The Company expects that capital expenditures to comply with existing statutes and regulations will be $341 million, $427 million, and $452 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 could range from $74 million to $289 million in 2011, $191 million to $670 million in 2012, and $476 million to $1.9 billion 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 fuel mix of the electric utilities.

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 significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' 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 Southern Company. Through 2010, the electric utilities had spent approximately $7 billion 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. A 20-county area within metropolitan Atlanta is the only location within Southern Company's service area that is currently designated as nonattainment for the current standard. On November 30, 2010, the EPA extended the attainment date for this area by one year as a result of improving air quality. 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 Southern 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 Southern Company's service area in Alabama and Georgia. State implementation plans demonstrating attainment with the annual standard for all areas have been submitted to the EPA. In September 2006, the EPA published a final rule which increased the stringency of the 24-hour average fine particulate matter air quality standard. In October 2009, the EPA designated the Birmingham area as nonattainment for the 24-hour standard. In April 2010, the State of Alabama requested that the EPA re-designate Birmingham to attainment for the 24-hour standard based on current air quality data. In September 2010, the EPA determined that Birmingham has air quality data that meets the 24-hour standard. 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 Southern 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 each of the states within Southern Company's service area, 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. States in the Southern Company service territory have completed plans to implement CAIR, and emissions reductions are being accomplished by the installation and operation of emissions controls at coal-fired facilities of the electric utilities 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 Alabama, 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 each of the states in Southern Company's service territory, 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 any of the traditional operating companies' 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.

On April 29, 2010, the EPA issued a proposed Industrial Boiler (IB) MACT rule that would establish emissions limits for various hazardous air pollutants typically emitted from industrial boilers, including biomass boilers and start-up boilers. The EPA issued the final rules on February 23, 2011 and, at the same time, issued a notice of intent to reconsider the final rules to allow for additional public review and comment. The impact of these regulations will depend on their final form and the outcome of any legal challenges and cannot be determined at this time.

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 rules for electric generating units and industrial boilers 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 has already installed a number of SO_2 and NO_x emissions controls to ensure continued compliance with applicable air quality requirements.

In addition to the federal air quality laws described above, Georgia Power also is subject to the requirements of the State of Georgia's Multi-Pollutant Rule, which was adopted in 2007. The Multi-Pollutant Rule is designed to reduce emissions of mercury, SO_2, and NO_x state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and June 1, 2015. The State of Georgia also adopted a companion rule that requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2010, Georgia Power had installed the required controls on 10 of its largest coal-fired generating units and is in the process of installing the required controls on six additional units. As a result of uncertainties related to the potential federal air quality regulations described above, Georgia Power has suspended certain work related to both the installation of emissions control equipment at Plant Branch Units 1 and 2 and Plant Yates Units 6 and 7 and the conversion of Plant Mitchell from coal-fired to biomass-fired. Georgia Power continues to analyze the potential costs and benefits of installing the required controls on its remaining coal-fired generating units in light of the potential federal regulations described above. Georgia Power may determine that retiring and replacing certain of these existing units with new generating resources or purchased power is more economically efficient than installing the required environmental controls.

Georgia Power currently expects to file an update to its integrated resource plan in June 2011. Under the terms of an Alternate Rate Plan approved by the Georgia PSC for Georgia Power which became effective January 1, 2011 and will continue through December 31, 2013 (the 2010 ARP), any costs associated with changes to Georgia Power's approved environmental operating or capital budgets (resulting from new or revised environmental regulations) through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. Such costs that may be deferred as a regulatory asset include any impairment losses that may result from a decision to retire certain units that are no longer cost effective in light of new or modified environmental regulations. In addition, in connection with the 2010 ARP, the Georgia PSC also approved revised depreciation rates that will recover the remaining book value of certain of Georgia Power's existing coal-fired units by December 31, 2014.

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

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 traditional operating companies, the traditional operating companies 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 Southern Company system 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.

Environmental Remediation

Southern 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 traditional operating companies could incur substantial costs to clean up properties. The traditional operating companies conduct studies to determine the extent of any required cleanup and have recognized in their respective financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The traditional operating companies 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 traditional operating companies currently operate 22 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 traditional operating companies also sell a portion of their coal combustion byproducts to third parties for beneficial reuse (approximately one-fourth in recent years). Historically, individual states have regulated coal combustion byproducts and the states in Southern Company's service territory each have their own regulatory parameters. Each traditional operating 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. Southern Company regards these estimates as pre-screening figures that should be distinguished from the more formalized cost estimates Southern 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 traditional operating companies could incur additional material asset retirement obligations with respect to closing existing storage facilities. Southern 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, natural gas, and biomass 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 electric utilities were approximately 121 million metric tons. The preliminary estimate of carbon dioxide emissions from these units in 2010 is approximately 131 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 is actively evaluating and developing electric generating technologies with lower greenhouse gas emissions. These include, but are not limited to, new nuclear generation, including two additional nuclear units on the site of Plant Vogtle (Plant Vogtle Units 3 and 4) in Georgia; construction of the Kemper IGCC in Mississippi with 65% carbon capture; and renewables investments, including the construction of a biomass plant in Sacul, Texas. In addition, a subsidiary of the Company completed construction on a solar photovoltaic plant near Cimarron, New Mexico in 2010. The Company is currently considering additional projects and is pursuing research into the costs and viability of other renewable technologies.

PSC Matters

Alabama Power

Rate RSE

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

The Rate RSE increase for 2010 was 3.24%, or $152 million annually, and was effective in January 2010. In December 2010, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2011 and earnings were within the specified return range. Consequently, the retail rates will remain unchanged in 2011 under Rate RSE. Under the terms of Rate RSE, the maximum increase for 2012 cannot exceed 5.00%.

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under a Rate CNP. There was no adjustment to the Rate CNP to recover certificated PPA costs in 2008 or 2009. Effective April 2010, Rate CNP was reduced by approximately $70 million annually, primarily due to the expiration on May 31, 2010 of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. It is estimated that there will be a slight decrease to the current Rate CNP effective April 2011.

Rate CNP also allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Retail rates increased approximately 2.4% in January 2008 and 4.3% in January 2010 due to environmental costs. In October 2008, Alabama Power agreed to defer collection of any increase in rates under this portion of Rate CNP, which permits recovery of costs associated with environmental laws and regulations, from 2009 until 2010. The deferral of the retail rate adjustments had an immaterial impact on annual cash flows, and had no significant effect on the Company's revenues or net income. On December 1, 2010, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflects an incremental increase in the revenue requirement associated with such environmental compliance, which would be recoverable in the billing months of January 2011 through December 2011. In order to afford additional rate stability to customers as the economy continues to recover from the recession, the Alabama PSC ordered on January 4, 2011 that Alabama Power leave in effect for 2011 the factors associated with Alabama Power's environmental compliance costs for the year 2010. Any recoverable amounts associated with 2011 will be reflected in the 2012 filing. The ultimate outcome of this matter cannot be determined at this time.

Natural Disaster Reserve

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

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

On August 20, 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows Alabama Power to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

For the year ended December 31, 2010, Alabama Power accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. For the year ended December 31, 2009, Alabama Power accrued an additional $40 million to the NDR, resulting in an accumulated balance of approximately $75 million. These accruals are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

Nuclear Outage Accounting Order

On August 17, 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, Alabama Power accrued nuclear outage operations and maintenance expenses for the two units of Plant Farley during the 18-month cycle for the outages. In accordance with the new order, nuclear outage expenses will be deferred when the charges actually occur and then amortized over the subsequent 18-month period.

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

Georgia Power

The economic recession significantly reduced Georgia Power's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 (2007 Retail Rate Plan). In June 2009, despite stringent efforts to reduce expenses, Georgia Power's projected retail ROE for both 2009 and 2010 was below 10.25%. However, in lieu of filing to increase customer rates as allowed under the 2007 Retail Rate Plan, in June 2009, Georgia Power filed a request with the Georgia PSC for an accounting order that would allow Georgia Power to amortize up to $324 million of its regulatory liability related to other cost of removal obligations.

In August 2009, the Georgia PSC approved the accounting order. Under the terms of the accounting order, Georgia Power could amortize up to $108 million of the regulatory liability in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, Georgia Power amortized $41 million and $174 million of the regulatory liability, respectively.

On December 21, 2010, the Georgia PSC approved the 2010 ARP. The terms of the 2010 ARP reflect a settlement agreement among Georgia Power, the Georgia PSC's Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, Georgia Power will amortize approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

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

Under the 2010 ARP, the following additional base rate adjustments will be made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs will increase by $17 million;
- Effective April 1, 2012, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4 and 5 for the period from commercial operation through December 31, 2013;
- Effective January 1, 2013, the DSM tariffs will increase by $18 million;
- Effective January 1, 2013, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Unit 6 for the period from commercial operation through December 31, 2013; and
- The MFF tariff will increase consistent with these adjustments.

Georgia Power currently estimates these adjustments will result in annualized base revenue increases of approximately $190 million in 2012 and $93 million in 2013.

Under the 2010 ARP, Georgia Power's retail ROE is set at 11.15% and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. If at any time during the term of the 2010 ARP, Georgia Power projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust Georgia Power's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, Georgia Power may file a full rate case.

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

Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. In previous years, the traditional operating companies experienced higher than expected fuel costs for coal, natural gas, and uranium. These higher fuel costs have resulted in total under recovered fuel costs included in the balance sheets of Alabama Power, Georgia Power, and Gulf Power of approximately $420 million at December 31, 2010. As of December 31, 2010, Mississippi Power had a total over recovered fuel balance of $55 million. At December 31, 2009, total under recovered fuel costs included in the balance sheets of Georgia Power and Gulf Power were approximately $667 million and Alabama Power and Mississippi Power had a total over recovered fuel balance of approximately $229 million. The traditional operating companies continuously monitor the under or over recovered fuel cost balances.

Fuel cost recovery revenues 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 Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Fuel Cost Recovery" and "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" for additional information.

Legislation

Stimulus Funding

On April 28, 2010, Southern Company signed a Smart Grid Investment Grant agreement with the U.S. Department of Energy (DOE), formally accepting a $165 million grant under the American Recovery and Reinvestment Act of 2009. This funding, to be matched by Southern Company, will be used for transmission and distribution automation and modernization projects that must be completed by April 28, 2013. 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, Southern Company and the traditional operating companies have 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 financial statements of Southern Company. 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 financial statements of Southern Company 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

Georgia State Income Tax Credits

Georgia Power's 2005 through 2009 income tax filings for the State of Georgia include state income tax credits for increased activity through Georgia ports. Georgia Power also filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue (DOR) has not responded to these claims. In July 2007, Georgia Power filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On March 22, 2010, the Superior Court of Fulton County ruled in favor of Georgia Power's motion for summary judgment. The Georgia DOR has appealed to the Georgia Court of Appeals and a decision is expected later this year. Any decision may be subject to further appeal to the Georgia Supreme Court. An unrecognized tax benefit has been recorded related to these credits. If Georgia Power prevails, no material impact on Southern Company's net income is expected as a significant portion of any tax benefit is expected to be returned to retail customers in accordance with the 2010 ARP. If Georgia Power is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on Southern Company's cash flow. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot now be determined.

Tax Method of Accounting for Repairs

Southern Company submitted a change in the tax accounting method for repair costs associated with Southern Company's generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. On a consolidated basis, the new tax method resulted in net positive cash flow in 2010 of approximately $297 million. Although Internal Revenue Service (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 Southern Company. The application of the bonus depreciation provisions in these acts in 2010 provided approximately $393 million in increased cash flow. Southern Company estimates the potential increased cash flow for 2011 to be between approximately $500 million and $600 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 Southern 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 Southern 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.

Construction Program

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. Southern Company intends to continue its strategy of developing and constructing new generating facilities, including natural gas and biomass units at Southern Power, natural gas and new nuclear units at Georgia Power, and the Kemper IGCC at Mississippi Power, as well as adding environmental control equipment and expanding the transmission and distribution systems. For the traditional operating companies, major generation construction projects are subject to state PSC approvals in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. See Note 7 to the financial statements under "Construction Program" for estimated construction expenditures for the next three years. In addition, see Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction," "Retail Regulatory Matters – Georgia Power – Other Construction," and "Retail Regulatory Matters – Mississippi Power Integrated Coal Gasification Combined Cycle" for additional information.

On September 3, 2010, Georgia Power filed with the Georgia PSC the Nuclear Construction Cost Recovery (NCCR) tariff, as authorized in April 2009 under the Georgia Nuclear Energy Financing Act. The Georgia PSC has ordered Georgia Power to report against the total certified cost of Plant Vogtle Units 3 and 4 of approximately $6.1 billion. In addition, on December 21, 2010, the Georgia PSC approved Georgia Power's NCCR tariff. The NCCR tariff became effective January 1, 2011 and is expected to collect approximately $223 million during 2011 to recover financing costs associated with the construction of Plant Vogtle Units 3 and 4.

Other Matters

Southern Company and its subsidiaries are involved in various other matters being litigated, regulatory matters, and certain tax-related issues that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries 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 Southern Company and its subsidiaries 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 Southern 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

Southern Company prepares its consolidated 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 Southern 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

Southern Company's traditional operating companies, which comprised approximately 95% of Southern Company's total operating revenues for 2010, are subject to retail regulation by their respective state PSCs and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional operating companies are permitted to charge customers based on allowable costs. As a result, the traditional operating companies apply 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 traditional operating companies; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations 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

Southern Company and its subsidiaries are subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject them 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. Southern 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 Southern 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 Southern Company or its subsidiaries may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which Southern Company or its subsidiaries 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, and 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.

Alabama Power is better able to determine unbilled KWH sales due to the installation of automated meters. At the end of each month, amounts of electricity delivered are read for the customers with automated meters. From this reading, unbilled KWH sales are determined and included in Alabama Power's unbilled revenue calculation. For customers without automated meter readings, amounts of unbilled electricity delivered are estimated.

Pension and Other Postretirement Benefits

Southern 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 Southern 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 Southern Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. Southern Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to Southern Company's target asset allocation. Southern 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.

The following table illustrates the sensitivity to changes in Southern Company's long-term assumptions with respect to the expected long-term rate of return on plan assets and the assumed discount rate:

Change in Assumption	Increase/(Decrease) in Total Benefit Expense for 2011	Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2010	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2010
		(in millions)	
25 basis point change in discount rate	$25/$(17)	$249/$(236)	$52/$(50)
25 basis point change in salary assumption	$13/$(12)	$63/$(60)	N/M
25 basis point change in long-term return on plan assets	$20/$(20)	N/M	N/M

N/M – Not meaningful

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Company's financial condition remained stable at December 31, 2010. Southern 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.

Southern Company's investments in the qualified pension plan and the nuclear decommissioning trust funds remained stable in value as of December 31, 2010. In December 2010, the traditional operating companies and certain other subsidiaries contributed $620 million to the qualified pension plan. Southern Company does not expect any material changes to funding obligations to the nuclear decommissioning trust funds prior to 2014.

Net cash provided from operating activities in 2010 totaled $4 billion, an increase of $728 million from the corresponding period in 2009. Significant changes in operating cash flow for 2010 as compared to the corresponding period in 2009 include an increase in net income, a reduction in fossil fuel stock, and an increase in deferred income taxes primarily due to the change in the tax accounting method for repair costs. A contribution to the qualified pension plan partially offset these increases. Net cash provided from operating activities in 2009 totaled $3.3 billion, a decrease of $201 million from the corresponding period in 2008. Significant changes in operating cash flow for 2009 as compared to the corresponding period in 2008 include a reduction to net income, increased levels of coal inventory, and increased cash outflows for tax payments. These uses of funds were partially offset by increased cash inflows as a result of higher fuel cost recovery rates included in customer billings. Net cash provided from operating activities in 2008 totaled $3.5 billion, an increase of $30 million as compared to 2007. Significant changes in operating cash flow for 2008 included a $264 million increase in the use of funds for fossil fuel inventory as compared to the corresponding period in 2007. This use of funds was offset by an increase in cash of $312 million in accrued taxes primarily due to a difference between the periods in payments for federal taxes and property taxes.

Net cash used for investing activities in 2010 totaled $4.3 billion primarily due to property additions to utility plant. Net cash used for investing activities in 2009 totaled $4.3 billion primarily due to property additions to utility plant of $4.7 billion, partially offset by approximately $340 million in cash received from the early termination of two leveraged lease investments. Net cash used for investing activities in 2008 totaled $4.1 billion primarily due to property additions to utility plant of $4.0 billion.

Net cash provided from financing activities totaled $22 million in 2010, a decrease of $1.3 billion from the corresponding period in 2009. This decrease was primarily due to redemptions of long-term debt in 2010. Net cash provided from financing activities totaled $1.3 billion in 2009 primarily due to the issuances of new long-term debt and common stock, partially offset by cash outflows for repayments of long-term debt and dividend payments. Net cash provided from financing activities totaled $878 million in 2008 primarily due to long-term debt issuances.

Significant balance sheet changes in 2010 include an increase of $2.8 billion in total property, plant, and equipment for the installation of equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities. Other significant changes include an increase in notes payable of $658 million used primarily for construction expenditures and general corporate purposes and $1.3 billion of additional equity.

At the end of 2010, the closing price of Southern Company's common stock was $38.23 per share, compared with book value of $19.21 per share. The market-to-book value ratio was 199% at the end of 2010, compared with 184% at year-end 2009.

Sources of Capital

Southern Company intends to meet its future capital needs through internal cash flow and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital to be raised in 2011, as well as in subsequent years, will be contingent on Southern Company's investment opportunities.

Except as described below with respect to potential DOE loan guarantees, the traditional operating companies and Southern Power plan to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

On June 18, 2010, Georgia Power reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future Georgia Power borrowings related to Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to Georgia Power and secured by a first priority lien on Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs, or approximately $3.4 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to receipt of the combined construction and operating license for Plant Vogtle Units 3 and 4 from the Nuclear Regulatory Commission (NRC), negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. There can be no assurance that the DOE will issue loan guarantees for Georgia Power.

In addition, Mississippi Power has applied to the DOE for federal loan guarantees to finance a portion of the eligible construction costs of the Kemper IGCC. Mississippi Power is in advanced due diligence with the DOE but has yet to begin discussions with the DOE regarding the terms and conditions of any loan guarantee. There can be no assurance that the DOE will issue federal loan guarantees for Mississippi Power.

The issuance of securities by the traditional operating companies is generally subject to the approval of the applicable state PSC. The issuance of all securities by Mississippi Power and Southern Power and short-term securities by Georgia Power is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Company and certain of its subsidiaries file 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 appropriate regulatory authorities, 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.

Southern Company, each traditional operating company, and Southern Power obtain 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 each company are not commingled with funds of any other company.

Southern Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet cash needs as well as scheduled maturities of long-term debt. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets, including commercial paper programs (which are backed by bank credit facilities).

At December 31, 2010, Southern Company and its subsidiaries had approximately $447.4 million of cash and cash equivalents and $4.8 billion of unused credit arrangements with banks, of which $1.6 billion expire in 2011 and $3.2 billion expire in 2012. Approximately $81 million of the credit facilities expiring in 2011 allow for the execution of term loans for an additional two-year period, and $927 million allow for the execution of one-year term loans. Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of the individual company. Southern Company and its subsidiaries are currently in compliance with all such covenants. A portion of the unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support as of December 31, 2010 was approximately $1.3 billion. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The traditional operating companies 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 each of the traditional operating companies. At December 31, 2010, the Southern Company system had approximately $1.3 billion of commercial paper borrowings outstanding with a weighted average interest rate of 0.3% per annum. During 2010, Southern Company had an average of $690 million of commercial paper outstanding at a weighted average interest rate of 0.3% per annum and the maximum amount outstanding was $1.3 billion. At December 31, 2009, the Southern Company system had approximately $638 million of commercial paper borrowings outstanding with a weighted average interest rate of 0.3% per annum. During 2009, Southern Company had an average of $956 million of commercial paper outstanding at a weighted average interest rate of 0.4% per annum and the maximum amount outstanding for commercial paper was $1.4 billion. Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

During 2010, Southern Company issued $400 million aggregate principal amount of Series 2010A 2.375% Senior Notes due September 15, 2015. The net proceeds were used to redeem $250 million aggregate principal amount of Southern Company Capital Funding, Inc.'s Series C 5.75% Senior Notes due November 15, 2015. In addition, certain Southern Company subsidiaries issued $2.8 billion of senior notes and other long-term debt and entered into bank term loan agreements of $125 million. The proceeds were used to repay maturing long-term and short-term indebtedness and for other general corporate purposes, including the applicable subsidiary's continuous construction program. Southern Company also issued 19.6 million shares of common stock for $629 million through the Southern Investment Plan and employee and director stock plans. In addition, Southern Company issued 4.1 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity offering program and received cash proceeds of $143 million, net of $1 million in fees and commissions. The proceeds from the sale of the common stock were used by the Company for general corporate purposes, including the investment by the Company in its subsidiaries, and to repay a portion of its outstanding short-term indebtedness.

In December 2010, Mississippi Power incurred obligations in connection with the issuance of $100 million of revenue bonds in two series, each of which is due December 1, 2040. The first series of $50 million was issued with an initial fixed rate of 2.25% through January 14, 2013 and the second series of $50 million was issued with a floating rate. The proceeds from the first series bonds were used to finance the acquisition and construction of buildings and immovable equipment in connection with Mississippi Power's construction of the Kemper IGCC. Proceeds from the second series bonds were classified as restricted cash at December 31, 2010 and these bonds were redeemed on February 8, 2011.

Subsequent to December 31, 2010, Alabama Power entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $200 million.

Also subsequent to December 31, 2010, Georgia Power issued $300 million aggregate principal amount of Series 2011A Floating Rate Senior Notes due January 15, 2013. The proceeds were used to repay a portion of Georgia Power's outstanding short-term indebtedness and for general corporate purposes, including Georgia Power's continuous construction program.

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

Off-Balance Sheet Financing Arrangements

In 2001, Mississippi Power began the initial 10-year term of a lease agreement for a combined cycle generating facility built at Plant Daniel for approximately $370 million. In 2003, the generating facility was acquired by Juniper Capital L.P. (Juniper), a limited partnership whose investors are unaffiliated with Mississippi Power. Simultaneously, Juniper entered into a restructured lease agreement with Mississippi Power. Juniper has also entered into leases with other parties unrelated to Mississippi Power. The assets leased by Mississippi Power comprise less than 50% of Juniper's assets. Mississippi Power is not required to consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. The lease also provides for a residual value guarantee, approximately 73% of the acquisition cost, by Mississippi Power that is due upon termination of the lease in the event that Mississippi Power does not renew the lease or purchase the assets and that the fair market value is less than the unamortized cost of the assets. In April 2010, Mississippi Power was required to notify the lessor, Juniper, if it intended to terminate the lease at the end of the initial term expiring in October 2011. Mississippi Power chose not to give notice to terminate the lease. Mississippi Power has the option to purchase the Plant Daniel combined cycle generating units for approximately $354 million or renew the lease for approximately $31 million annually for 10 years. Mississippi Power will have to provide notice of its intent to either renew the lease or purchase the facility by July 2011. The ultimate outcome of this matter cannot be determined at this time. See Note 7 to the financial statements under "Operating Leases" for additional information.

Credit Rating Risk

Southern 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 of certain subsidiaries to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, energy price risk management, and construction of new generation. At December 31, 2010, the maximum potential collateral requirements under these contracts at a BBB and Baa2 rating were approximately $9 million and at a BBB- and/or Baa3 rating were approximately $489 million. At December 31, 2010, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $2.5 billion. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Southern 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 Southern Company (senior unsecured to Baa1 from A3); Moody's also announced that it had downgraded the short-term ratings of Southern Company and a financing subsidiary of Southern Company that issues commercial paper for the benefit of several Southern Company subsidiaries (including Georgia Power, Gulf Power, and Mississippi Power) to P-2 from P-1. In addition, Moody's downgraded the issuer and long-term debt ratings of Georgia Power (senior unsecured to A3 from A2), Gulf Power (senior unsecured to A3 from A2), and Mississippi Power (senior unsecured to A2 from A1). All of these companies have stable ratings outlooks from Moody's.

On September 3, 2010, Fitch Ratings, Inc. (Fitch) confirmed the long-term debt ratings of Southern Company (senior unsecured A), but announced that the ratings outlook of Southern Company had been revised to negative, and that the issuer default ratings and long-term debt ratings of Mississippi Power had been downgraded by one notch (senior unsecured to A+ from AA- and issuer default rating to A from A+). On December 22, 2010, Fitch announced that the ratings outlook of Southern Company and Georgia Power had been revised from negative to stable.

Market Price Risk

Southern Company is exposed to market risks, primarily commodity price risk and interest rate risk. The Company may also occasionally have limited exposure to foreign currency exchange rates. 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. Company 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 a change in interest rates, Southern Company and certain of its subsidiaries enter into derivatives that have been designated as hedges. Derivatives outstanding at December 31, 2010 have a notional amount of $650 million and are related to fixed and floating rate obligations over the next several years. The weighted average interest rate on $2.5 billion of long-term variable interest rate exposure that has not been hedged at January 1, 2011 was 0.75%. If Southern Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $25 million at January 1, 2011. For further information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies enter 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 traditional operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs.

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 millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$(178)**	$(285)
Contracts realized or settled	**197**	367
Current period changes[(a)]	**(215)**	(260)
Contracts outstanding at the end of the period, assets (liabilities), net	**$(196)**	$(178)

(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 a decrease of $18 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2010, Southern Company had a net hedge volume of 149 million mmBtu with a weighted average contract cost approximately $1.35 per mmBtu above market prices, compared to 145 million mmBtu at December 31, 2009 with a weighted average contract cost approximately $1.23 per mmBtu above market prices. The majority of the natural gas hedges are recovered through the traditional operating companies' fuel cost recovery clauses.

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets (liabilities) were as follows:

Asset (Liability) Derivatives	**2010**	2009
	(in millions)	
Regulatory hedges	**$(193)**	$(175)
Cash flow hedges	**(1)**	(2)
Not designated	**(2)**	(1)
Total fair value	**$(196)**	$(178)

Energy-related derivative contracts which are designated as regulatory hedges relate to the traditional operating companies' fuel hedging programs, where 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 clauses. Gains and losses on energy-related derivatives that are designated as cash flow hedges are mainly used by Southern Power to hedge anticipated purchases and sales and are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Total net unrealized pre-tax gains (losses) recognized in the statements of income for the years ended December 31, 2010, 2009, and 2008 for energy-related derivative contracts that are not hedges were $(2) million, $(5) million, and $1 million, respectively.

Southern 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 10 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 millions)			
Level 1	$ -	$ -	$ -	$ -
Level 2	(196)	(144)	(52)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$ (196)	$ (144)	$(52)	$ -

Southern Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. Southern Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's 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, Southern Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

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

Southern Company performs periodic reviews of its leveraged lease transactions, both domestic and international and the creditworthiness of the lessees, including a review of the value of the underlying leased assets and the credit ratings of the lessees. Southern Company's domestic lease transactions generally do not have any credit enhancement mechanisms; however, the lessees in its international lease transactions have pledged various deposits as additional security to secure the obligations. The lessees in the Company's international lease transactions are also required to provide additional collateral in the event of a credit downgrade below a certain level.

Capital Requirements and Contractual Obligations

The construction programs of the Company's subsidiaries are currently estimated to include a base level investment of $4.9 billion, $5.1 billion, and $4.5 billion for 2011, 2012, and 2013, respectively. Included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $341 million, $427 million, and $452 million for 2011, 2012, and 2013, respectively. In addition, the Company currently estimates that potential incremental investments to comply with anticipated new environmental regulations could range from $74 million to $289 million for 2011, $191 million to $670 million for 2012, and $476 million to $1.9 billion for 2013. The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction," "Retail Regulatory Matters – Georgia Power – Other Construction," and "Retail Regulatory Matters –Mississippi Power Integrated Coal Gasification Combined Cycle" and Note 7 to the financial statements under "Construction Program" for additional information.

As a result of NRC requirements, Alabama Power and Georgia Power have external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, Southern Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the traditional operating companies' respective regulatory commissions.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2011	2012-2013	2014-2015	After 2015	Uncertain Timing[d]	Total
			(in millions)			
Long-term debt[a] –						
Principal	$1,278	$2,938	$1,138	$14,029	$ -	$19,383
Interest	876	1,610	1,369	11,194	-	15,049
Preferred and preference stock dividends[b]	65	130	130	-	-	325
Energy-related derivative obligations[c]	151	55	-	-	-	206
Operating leases	154	170	94	103	-	521
Capital leases	23	28	13	35	-	99
Unrecognized tax benefits and interest[d]	203	-	-	-	122	325
Purchase commitments[e] –						
Capital[f]	4,554	9,242	-	-	-	13,796
Limestone[g]	39	82	72	89	-	282
Coal	3,810	3,244	1,656	1,798	-	10,508
Nuclear fuel	335	427	349	807	-	1,918
Natural gas[h]	1,357	2,280	1,687	3,413	-	8,737
Biomass fuel[i]	-	32	36	110	-	178
Purchased power	260	506	559	2,439	-	3,764
Long-term service agreements[j]	110	270	290	1,435	-	2,105
Trusts –						
Nuclear decommissioning[k]	3	4	4	35	-	46
Pension and other postretirement benefit plans[l]	64	147	-	-	-	211
Total	$13,282	$21,165	$7,397	$35,487	$ 122	$77,453

(a) All amounts are reflected based on final maturity dates. Southern Company and its subsidiaries plan 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. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

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

(d) The timing related to the realization of $122 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 Notes 3 and 5 to the financial statements for additional information.

(e) Southern 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 $4.0 billion, $3.5 billion, and $3.8 billion, respectively.

(f) Southern Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel. In addition, such amounts exclude Southern Company's estimates of potential incremental investments to comply with anticipated new environmental regulations which could range from $74 million to $289 million for 2011, $191 million to $670 million for 2012, and $476 million to $1.9 billion for 2013. At December 31, 2010, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of Southern Company's program to reduce SO_2 emissions from its coal plants, the traditional operating companies have 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) Biomass fuel commitments are based on minimum committed tonnage of wood waste purchases.

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

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

(l) Southern Company forecasts contributions to the qualified pension and other postretirement benefit plans over a three-year period. Southern 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 Southern Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2010 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the wholesale business, retail sales, customer growth, economic recovery, fuel cost recovery and other rate actions, environmental regulations and expenditures, future earnings, dividend payout ratios, access to sources of capital, projections for the qualified pension plan, postretirement benefit, and nuclear decommissioning trust fund contributions, financing activities, start and completion of construction projects, plans and estimated costs for new generation resources, 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 Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and IRS audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- 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 Southern Company's employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to the Plant Vogtle expansion, including Georgia PSC and NRC approvals and potential DOE loan guarantees;
- regulatory approvals and actions related to the Kemper IGCC, including Mississippi PSC approvals and potential DOE loan guarantees;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- 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 Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries 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 Southern 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 Southern Company's and its subsidiaries' credit ratings;
- the ability of Southern Company and its subsidiaries 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 Southern 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.

Southern Company expressly disclaims any obligation to update any forward-looking statements.

CONSOLIDATED STATEMENTS OF INCOME

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

Southern Company and Subsidiary Companies 2010 Annual Report

	2010	2009	2008
		(in millions)	
Operating Revenues:			
Retail revenues	**$14,791**	$13,307	$14,055
Wholesale revenues	**1,994**	1,802	2,400
Other electric revenues	**589**	533	545
Other revenues	**82**	101	127
Total operating revenues	**17,456**	15,743	17,127
Operating Expenses:			
Fuel	**6,699**	5,952	6,818
Purchased power	**563**	474	815
Other operations and maintenance	**4,010**	3,526	3,748
MC Asset Recovery litigation settlement	**-**	202	-
Depreciation and amortization	**1,513**	1,503	1,443
Taxes other than income taxes	**869**	818	797
Total operating expenses	**13,654**	12,475	13,621
Operating Income	**3,802**	3,268	3,506
Other Income and (Expense):			
Allowance for equity funds used during construction	**194**	200	152
Interest income	**24**	23	33
Leveraged lease income (losses)	**18**	31	(85)
Gain on disposition of lease termination	**-**	26	-
Loss on extinguishment of debt	**-**	(17)	-
Interest expense, net of amounts capitalized	**(895)**	(905)	(866)
Other income (expense), net	**(77)**	(22)	(18)
Total other income and (expense)	**(736)**	(664)	(784)
Earnings Before Income Taxes	**3,066**	2,604	2,722
Income taxes	**1,026**	896	915
Consolidated Net Income	**2,040**	1,708	1,807
Dividends on Preferred and Preference Stock of Subsidiaries	**65**	65	65
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	**$ 1,975**	$ 1,643	$ 1,742
Common Stock Data:			
Earnings per share (EPS)–			
Basic EPS	**$2.37**	$2.07	$2.26
Diluted EPS	**2.36**	2.06	2.25
Average number of shares of common stock outstanding – (in millions)			
Basic	**832**	795	771
Diluted	**837**	796	775
Cash dividends paid per share of common stock	**$1.8025**	$1.7325	$1.6625

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2010, 2009, and 2008
Southern Company and Subsidiary Companies 2010 Annual Report

	2010	2009	2008
		(in millions)	
Operating Activities:			
Consolidated net income	**$ 2,040**	$ 1,708	$ 1,807
Adjustments to reconcile consolidated net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**1,831**	1,788	1,704
Deferred income taxes	**1,038**	25	215
Deferred revenues	**(103)**	(54)	120
Allowance for equity funds used during construction	**(194)**	(200)	(152)
Leveraged lease (income) losses	**(18)**	(31)	85
Gain on disposition of lease termination	**-**	(26)	-
Loss on extinguishment of debt	**-**	17	-
Pension, postretirement, and other employee benefits	**(614)**	(3)	21
Stock based compensation expense	**33**	23	20
Hedge settlements	**2**	(19)	15
Generation construction screening costs	**(51)**	(22)	-
Other, net	**86**	102	(108)
Changes in certain current assets and liabilities --			
-Receivables	**80**	585	(176)
-Fossil fuel stock	**135**	(432)	(303)
-Materials and supplies	**(30)**	(39)	(23)
-Other current assets	**(17)**	(47)	(36)
-Accounts payable	**4**	(125)	(74)
-Accrued taxes	**(308)**	(95)	293
-Accrued compensation	**180**	(226)	36
-Other current liabilities	**(103)**	334	20
Net cash provided from operating activities	**3,991**	3,263	3,464
Investing Activities:			
Property additions	**(4,086)**	(4,670)	(3,961)
Investment in restricted cash from revenue bonds	**(50)**	(55)	(96)
Distribution of restricted cash from revenue bonds	**25**	119	69
Nuclear decommissioning trust fund purchases	**(2,009)**	(1,234)	(720)
Nuclear decommissioning trust fund sales	**2,004**	1,228	712
Proceeds from property sales	**18**	340	34
Cost of removal, net of salvage	**(125)**	(119)	(123)
Change in construction payables	**(51)**	215	83
Other investing activities	**18**	(143)	(124)
Net cash used for investing activities	**(4,256)**	(4,319)	(4,126)
Financing Activities:			
Increase (decrease) in notes payable, net	**659**	(306)	(314)
Proceeds --			
Long-term debt issuances	**3,151**	3,042	3,687
Common stock issuances	**772**	1,286	474
Redemptions --			
Long-term debt	**(2,966)**	(1,234)	(1,469)
Redeemable preferred stock	**-**	-	(125)
Payment of common stock dividends	**(1,496)**	(1,369)	(1,280)
Payment of dividends on preferred and preference stock of subsidiaries	**(65)**	(65)	(66)
Other financing activities	**(33)**	(25)	(29)
Net cash provided from financing activities	**22**	1,329	878
Net Change in Cash and Cash Equivalents	**(243)**	273	216
Cash and Cash Equivalents at Beginning of Year	**690**	417	201
Cash and Cash Equivalents at End of Year	**$ 447**	$ 690	$ 417

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

CONSOLIDATED BALANCE SHEETS

At December 31, 2010 and 2009

Southern Company and Subsidiary Companies 2010 Annual Report

Assets	**2010**	2009
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 447**	$ 690
Restricted cash and cash equivalents	**68**	43
Receivables --		
Customer accounts receivable	**1,140**	953
Unbilled revenues	**420**	394
Under recovered regulatory clause revenues	**209**	333
Other accounts and notes receivable	**285**	375
Accumulated provision for uncollectible accounts	**(25)**	(25)
Fossil fuel stock, at average cost	**1,308**	1,447
Materials and supplies, at average cost	**827**	794
Vacation pay	**151**	145
Prepaid expenses	**784**	508
Other regulatory assets, current	**210**	167
Other current assets	**59**	49
Total current assets	**5,883**	5,873
Property, Plant, and Equipment:		
In service	**56,731**	53,588
Less accumulated depreciation	**20,174**	19,121
Plant in service, net of depreciation	**36,557**	34,467
Nuclear fuel, at amortized cost	**670**	593
Construction work in progress	**4,775**	4,170
Total property, plant, and equipment	**42,002**	39,230
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**1,370**	1,070
Leveraged leases	**624**	610
Miscellaneous property and investments	**277**	283
Total other property and investments	**2,271**	1,963
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**1,280**	1,047
Prepaid pension costs	**88**	-
Unamortized debt issuance expense	**178**	208
Unamortized loss on reacquired debt	**274**	255
Deferred under recovered regulatory clause revenues	**218**	373
Other regulatory assets, deferred	**2,402**	2,702
Other deferred charges and assets	**436**	395
Total deferred charges and other assets	**4,876**	4,980
Total Assets	**$55,032**	$52,046

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

CONSOLIDATED BALANCE SHEETS

At December 31, 2010 and 2009

Southern Company and Subsidiary Companies 2010 Annual Report

Liabilities and Stockholders' Equity	**2010**	2009
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 1,301**	$ 1,113
Notes payable	**1,297**	639
Accounts payable	**1,275**	1,329
Customer deposits	**332**	331
Accrued taxes --		
Accrued income taxes	**8**	13
Unrecognized tax benefits	**187**	166
Other accrued taxes	**440**	398
Accrued interest	**225**	218
Accrued vacation pay	**194**	184
Accrued compensation	**438**	248
Liabilities from risk management activities	**152**	125
Other regulatory liabilities, current	**88**	528
Other current liabilities	**535**	292
Total current liabilities	**6,472**	5,584
Long-Term Debt (See accompanying statements)	**18,154**	18,131
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**7,554**	6,455
Deferred credits related to income taxes	**235**	248
Accumulated deferred investment tax credits	**509**	448
Employee benefit obligations	**1,580**	2,304
Asset retirement obligations	**1,257**	1,201
Other cost of removal obligations	**1,158**	1,091
Other regulatory liabilities, deferred	**312**	278
Other deferred credits and liabilities	**517**	346
Total deferred credits and other liabilities	**13,122**	12,371
Total Liabilities	**37,748**	36,086
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	**375**	375
Total Stockholders' Equity (See accompanying statements)	**16,909**	15,585
Total Liabilities and Stockholders' Equity	**$55,032**	$52,046
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION
At December 31, 2010 and 2009
Southern Company and Subsidiary Companies 2010 Annual Report

		2010	2009	2010	2009
		(in millions)		*(percent of total)*	
Long-Term Debt:					
Long-term debt payable to affiliated trusts --					
Maturity	Interest Rates				
2044	5.88%	**$ 206**	$ 206		
Variable rate (3.39% at 1/1/11) due 2042		**206**	206		
Total long-term debt payable to affiliated trusts		**412**	412		
Long-term senior notes and debt --					
Maturity	Interest Rates				
2010	4.70%	**-**	102		
2011	4.00% to 5.57%	**304**	304		
2012	4.85% to 6.25%	**1,778**	1,778		
2013	1.30% to 6.00%	**1,436**	936		
2014	4.15% to 4.90%	**425**	425		
2015	2.38% to 5.75%	**1,184**	1,025		
2016 through 2048	2.25% to 8.20%	**9,438**	8,822		
Adjustable rates (at 1/1/11):					
2010	0.35% to 0.97%	**-**	990		
2011	0.56% to 0.78%	**915**	790		
2013	0.62%	**350**	-		
2040	0.44%	**50**	-		
Total long-term senior notes and debt		**15,880**	15,172		
Other long-term debt --					
Pollution control revenue bonds --					
Maturity	Interest Rates				
2016 through 2049	0.80% to 6.00%	**1,807**	1,973		
Variable rates (at 1/1/11):					
2011 through 2041	0.26% to 0.51%	**1,284**	1,612		
Total other long-term debt		**3,091**	3,585		
Capitalized lease obligations		**99**	98		
Unamortized debt (discount), net		**(27)**	(23)		
Total long-term debt (annual interest requirement -- $ 876 million)		**19,455**	19,244		
Less amount due within one year		**1,301**	1,113		
Long-term debt excluding amount due within one year		**18,154**	18,131	**51.2%**	53.2%

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2010 and 2009
Southern Company and Subsidiary Companies 2010 Annual Report

	2010	2009	**2010**	2009
	(in millions)		*(percent of total)*	
Redeemable Preferred Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value -- 4.20% to 5.44%				
Authorized - 20 million shares				
Outstanding - 1 million shares	**81**	81		
$1 par value -- 5.20% to 5.83%				
Authorized - 28 million shares				
Outstanding - 12 million shares: $25 stated value	**294**	294		
Total redeemable preferred stock of subsidiaries (annual dividend requirement -- $ 20 million)	**375**	375	**1.1**	1.1
Common Stockholders' Equity:				
Common stock, par value $5 per share --	**4,219**	4,101		
Authorized - 1 billion shares				
Issued -- 2010: 844 million shares				
-- 2009: 820 million shares				
Treasury -- 2010: 0.5 million shares				
-- 2009: 0.5 million shares				
Paid-in capital	**3,702**	2,995		
Treasury, at cost	**(15)**	(15)		
Retained earnings	**8,366**	7,885		
Accumulated other comprehensive income (loss)	**(70)**	(88)		
Total common stockholders' equity	**16,202**	14,878	**45.7**	43.6
Preferred and Preference Stock of Subsidiaries:				
Non-cumulative preferred stock				
$25 par value -- 6.00% to 6.13%				
Authorized - 60 million shares				
Outstanding - 2 million shares	**45**	45		
Preference stock				
Authorized - 65 million shares				
Outstanding - $1 par value -- 5.63% to 6.50%	**343**	343		
- 14 million shares (non-cumulative)				
- $100 par or stated value -- 6.00% to 6.50%	**319**	319		
- 3 million shares (non-cumulative)				
Total preferred and preference stock of subsidiaries (annual dividend requirement -- $ 45 million)	**707**	707	**2.0**	2.1
Total stockholders' equity	**16,909**	15,585		
Total Capitalization	**$35,438**	$34,091	**100.0%**	100.0%

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

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

Southern Company and Subsidiary Companies 2010 Annual Report

	Number of Common Shares		Common Stock				Accumulated Other Comprehensive	Preferred and Preference	
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings	Income (Loss)	Stock of Subsidiaries	Total
	(in thousands)					*(in millions)*			
Balance at December 31, 2007	763,503	(399)	$3,817	$1,454	$(11)	$7,155	$ (30)	$707	$13,092
Net income after dividends on preferred and preference stock of subsidiaries	-	-	-	-	-	1,742	-	-	1,742
Other comprehensive loss	-	-	-	-	-	-	(75)	-	(75)
Stock issued	14,113	-	71	402	-	-	-	-	473
Stock-based compensation	-	-	-	36	-	-	-	-	36
Cash dividends	-	-	-	-	-	(1,279)	-	-	(1,279)
Other	-	(25)	-	1	(1)	(6)	-	-	(6)
Balance at December 31, 2008	777,616	(424)	3,888	1,893	(12)	7,612	(105)	707	13,983
Net income after dividends on preferred and preference stock of subsidiaries	-	-	-	-	-	1,643	-	-	1,643
Other comprehensive income	-	-	-	-	-	-	17	-	17
Stock issued	42,536	-	213	1,074	-	-	-	-	1,287
Stock-based compensation	-	-	-	26	-	-	-	-	26
Cash dividends	-	-	-	-	-	(1,369)	-	-	(1,369)
Other	-	(81)	-	2	(3)	(1)	-	-	(2)
Balance at December 31, 2009	**820,152**	**(505)**	**4,101**	**2,995**	**(15)**	**7,885**	**(88)**	**707**	**15,585**
Net income after dividends on preferred and preference stock of subsidiaries	**-**	**-**	**-**	**-**	**-**	**1,975**	**-**	**-**	**1,975**
Other comprehensive income	**-**	**-**	**-**	**-**	**-**	**-**	**18**	**-**	**18**
Stock issued	**23,662**	**-**	**118**	**654**	**-**	**-**	**-**	**-**	**772**
Stock-based compensation	**-**	**-**	**-**	**52**	**-**	**-**	**-**	**-**	**52**
Cash dividends	**-**	**-**	**-**	**-**	**-**	**(1,496)**	**-**	**-**	**(1,496)**
Other	**-**	**31**	**-**	**1**	**-**	**2**	**-**	**-**	**3**
Balance at December 31, 2010	**843,814**	**(474)**	**$4,219**	**$3,702**	**$(15)**	**$8,366**	**$(70)**	**$707**	**$16,909**

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

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

Southern Company and Subsidiary Companies 2010 Annual Report

	2010	2009	2008
		(in millions)	
Consolidated Net Income	**$2,040**	$1,708	$1,807
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(3), and $(19), respectively	**(1)**	(4)	(30)
Reclassification adjustment for amounts included in net income, net of tax of $9, $18, and $7, respectively	**15**	28	11
Marketable securities:			
Change in fair value, net of tax of $(2), $1, and $(4), respectively	**(3)**	4	(7)
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss),net of tax of $1, $(8), and $(32), respectively	**6**	(12)	(51)
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**1**	1	2
Total other comprehensive income (loss)	**18**	17	(75)
Dividends on preferred and preference stock of subsidiaries	**(65)**	(65)	(65)
Consolidated Comprehensive Income	**$1,993**	$1,660	$1,667

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Southern Company (the Company) 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 – Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – are vertically integrated utilities providing electric service in four Southeastern states. 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 financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities where the Company has an equity investment, but is not the primary beneficiary. All material intercompany transactions have been eliminated in consolidation. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

The traditional operating companies, Southern Power, and certain of their subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC) and the traditional operating companies are also subject to regulation by their respective state public service commissions (PSC). The companies follow generally accepted accounting principles (GAAP) in the U.S. and comply with the accounting policies and practices prescribed by their respective commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates.

Regulatory Assets and Liabilities

The traditional operating companies are 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 millions)		
Deferred income tax charges	**$1,204**	$ 1,048	(a)
Deferred income tax charges – Medicare subsidy	**82**	-	(k)
Asset retirement obligations-asset	**79**	125	(a,i)
Asset retirement obligations-liability	**(82)**	(47)	(a,i)
Other cost of removal obligations	**(1,188)**	(1,307)	(a)
Deferred income tax credits	**(237)**	(249)	(a)
Loss on reacquired debt	**274**	255	(b)
Vacation pay	**151**	145	(c,i)
Under recovered regulatory clause revenues	**27**	40	(d)
Over recovered regulatory clause revenues	**(40)**	(218)	(d)
Building leases	**45**	47	(f)
Generating plant outage costs	**31**	39	(d)
Under recovered storm damage costs	**8**	22	(d)
Property damage reserves	**(216)**	(157)	(h)
Fuel hedging-asset	**211**	187	(d)
Fuel hedging-liability	**(7)**	(2)	(d)
Other assets	**171**	156	(d)
Environmental remediation-asset	**67**	68	(h,i)
Environmental remediation-liability	**(10)**	(13)	(h)
Environmental compliance cost recovery	**-**	(96)	(g)
Other liabilities	**(13)**	(51)	(j)
Retiree benefit plans	**2,041**	2,268	(e,i)
Total assets (liabilities), net	**$ 2,598**	$ 2,260	

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 other cost of removal liabilities will be settled and trued up following completion of the related activities. Other cost of removal obligations include $92 million at Georgia Power that will be amortized over a three-year period beginning January 1, 2011 in accordance with a Georgia PSC order. See Note 3 under “Retail Regulatory Matters – Georgia Power – Retail Rate Plans” for additional information.
(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.
(c) Recorded as earned by employees and recovered as paid, generally within one year.
(d) Recorded and recovered or amortized as approved by the appropriate state PSCs over periods not exceeding 10 years.
(e) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 for additional information.
(f) Recovered over the remaining lives of the buildings through 2026.
(g) Deferred revenue associated with the levelization of Georgia Power’s environmental compliance cost recovery (ECCR) tariff revenue for the years 2008 through 2010 in accordance with a Georgia PSC order.
(h) Recovered as storm restoration or environmental remediation expenses are incurred.
(i) Not earning a return as offset in rate base by a corresponding asset or liability.
(j) Recorded and recovered or amortized as approved by the appropriate state PSC over periods up to the life of the plant or the remaining life of the original issue or, if refinanced, over the life of the new issue which may range up to 50 years.
(k) Recovered and amortized as approved by the appropriate state PSCs over periods not exceeding 14 years. See Note 5 under “Current and Deferred Income Taxes” for additional information.

In the event that a portion of a traditional operating company’s operations is no longer subject to applicable accounting rules for rate regulation, such 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 traditional operating company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under “Retail Regulatory

Matters – Alabama Power," "Retail Regulatory Matters – Georgia Power," and "Retail Regulatory Matters – Mississippi Power Integrated Coal Gasification Combined Cycle" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract periods. 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 traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. 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 regulatory requirements, deferred investment tax credits (ITCs) for the traditional operating companies 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 $23 million in 2010, $24 million in 2009, and $23 million in 2008. At December 31, 2010, all ITCs available to reduce federal income taxes payable had been utilized.

Under the American Recovery and Reinvestment Act of 2009, certain projects at certain Southern Company subsidiaries are eligible for ITCs or cash grants. These subsidiaries have elected to receive ITCs. The credits are recorded as a deferred credit, which will be amortized over the life of the asset, and the tax basis of the asset is reduced by 50% of the credits received, resulting in a deferred tax asset. The subsidiaries have elected to recognize the tax benefit of this basis difference as a reduction to income tax expense as costs are incurred during the construction period. These basis differences will reverse and be recorded to income tax expense over the useful life of the asset once placed in service.

In accordance with accounting standards related to the uncertainty in income taxes, Southern 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.

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

	2010	2009
	(in millions)	
Generation	**$30,121**	$28,204
Transmission	**7,835**	7,380
Distribution	**14,870**	14,335
General	**3,116**	2,917
Plant acquisition adjustment	**43**	43
Utility plant in service	**55,985**	52,879
Information technology equipment and software	**216**	182
Communications equipment	**423**	423
Other	**107**	104
Other plant in service	**746**	709
Total plant in service	**$56,731**	$53,588

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific state PSC orders. Alabama Power and Georgia Power defer and amortize nuclear refueling costs over the unit's operating cycle. The refueling cycles for Alabama Power and Georgia Power range from 18 to 24 months for each unit. In accordance with a Georgia PSC order, Georgia Power also defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

The amount of non-cash property additions recognized for the years ended December 31, 2010, 2009, and 2008 was $427 million, $370 million, and $309 million, respectively. These amounts are comprised of construction related accounts payable outstanding at each year end together with retention amounts accrued during the respective year.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.3% in 2010, 3.2% in 2009, and 3.2% in 2008. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled $19.7 billion and $18.7 billion at December 31, 2010 and 2009, respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In August 2009, the Georgia PSC approved an accounting order allowing Georgia Power to amortize a portion of its regulatory liability related to other cost of removal obligations. See Note 3 under "Retail Regulatory Matters – Georgia Power – Retail Rate Plans" for additional information.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from three to 30 years. Accumulated depreciation for other plant in service totaled $441 million and $419 million at December 31, 2010 and 2009, respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the various state PSCs allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability. See Note 3 under "Retail Regulatory Matters – Georgia Power – Retail Rate Plans" for additional information related to Georgia Power's cost of removal regulatory liability.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facilities, Plants Farley, Hatch, and Vogtle. In addition, the Company has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, co-generation 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 various state PSCs, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

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

	2010	2009
	(in millions)	
Balance at beginning of year	**$1,206**	$1,185
Liabilities incurred	**-**	2
Liabilities settled	**(16)**	(10)
Accretion	**78**	77
Cash flow revisions	**(2)**	(48)
Balance at end of year	**$1,266**	$1,206

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (the Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities and the Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require, except for investments tied to market indices or other mutual funds, that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates. In addition, the NRC prohibits investments in securities of power reactor licensees. While Southern Company is allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by Southern Company, Alabama Power, and Georgia Power management. The Funds' managers are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

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

The Funds at Georgia Power participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to investment brokers for a fee. Securities so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2010 and 2009, approximately $141 million and $14 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $144 million and $14 million at December 31, 2010 and 2009, respectively, and can only be sold upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2010, investment securities in the Funds totaled $1.4 billion consisting of equity securities of $664 million, debt securities of $632 million, and $74 million of other securities. At December 31, 2009, investment securities in the Funds totaled $1.1 billion consisting of equity securities of $774 million, debt securities of $272 million, and $22 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $2.0 billion, $1.2 billion, and $712 million in 2010, 2009, and 2008, respectively, all of which were reinvested. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $139 million, of which $6 million related to securities held in the Funds at December 31, 2010. For 2009, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $215 million, of which $198 million related to securities held in the Funds at December 31, 2009. For 2008, fair value reductions, including reinvested interest and dividends and excluding the Funds' expenses, were $(278) million. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2010, the accumulated provisions for decommissioning were as follows:

	Plant Farley	**Plant Hatch**	**Plant Vogtle**
		(in millions)	
External trust funds	$553	$360	$206
Internal reserves	24	-	-
Total	$577	$360	$206

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current studies, which were performed in 2008 for Alabama Power's Plant Farley and in 2009 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plants Hatch and Vogtle:

	Plant Farley	**Plant Hatch**	**Plant Vogtle**
Decommissioning periods:			
Beginning year	2037	2034	2047
Completion year	2065	2063	2067
		(in millions)	
Site study costs:			
Radiated structures	$1,060	$583	$500
Non-radiated structures	72	46	71
Total	$1,132	$629	$571

The decommissioning periods and site study costs for Plant Vogtle reflect the extended operating license approved by the NRC in June 2009. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study, and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2006. The estimates used in current rates are $575 million and $420 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Amounts expensed were $3 million annually for Plant Vogtle Units 1 and 2 for 2008 through 2010. Effective for the years 2011 through 2013, the annual decommissioning cost for ratemaking is $2 million for Plant Hatch. Georgia Power projects the external trust funds for Plant Vogtle Units 1 and 2 would be adequate to meet the decommissioning obligations of the NRC with no further contributions. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and 2.4% for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0% and 4.4% for Alabama Power and Georgia Power, respectively. As a result of license extensions, amounts previously contributed to the external trust funds for Plant Farley are currently projected to be adequate to meet the decommissioning obligations.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized

In accordance with regulatory treatment, the traditional operating companies record 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. Interest related to the construction of new facilities not included in the traditional operating companies' regulated rates is capitalized in accordance with standard interest capitalization requirements. AFUDC and interest capitalized, net of income taxes were 12.5%, 15.3%, and 11.2% of net income for 2010, 2009, and 2008, respectively.

Cash payments for interest totaled $789 million, $788 million, and $787 million in 2010, 2009, and 2008, respectively, net of amounts capitalized of $86 million, $84 million, and $71 million, respectively.

Impairment of Long-Lived Assets and Intangibles

Southern 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.

Storm Damage Reserves

Each traditional operating company maintains a reserve to cover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In accordance with their respective state PSC orders, the traditional operating companies accrued $32 million in 2010 and $44 million in 2009. Alabama Power, Gulf Power, and Mississippi Power also have discretionary authority from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2010 and 2009, such additional accruals totaled $48 million and $40 million, respectively, all at Alabama Power. There were no material accruals for 2008. See Note 3 under "Retail Regulatory Matters – Alabama Power – Natural Disaster Reserve" for additional information regarding Alabama Power's natural disaster reserve.

Leveraged Leases

Southern Company has several leveraged lease agreements, with terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. The Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows.

Southern Company's net investment in domestic leveraged leases consists of the following at December 31:

	2010	2009
	(in millions)	
Net rentals receivable	**$475**	$487
Unearned income	**(207)**	(218)
Investment in leveraged leases	**268**	269
Deferred taxes from leveraged leases	**(223)**	(211)
Net investment in leveraged leases	**$ 45**	$ 58

A summary of the components of income from domestic leveraged leases was as follows:

	2010	2009	2008
		(in millions)	
Pretax leveraged lease income	**$4**	$12	$14
Income tax expense	**(3)**	(5)	(6)
Net leveraged lease income	**$1**	$ 7	$ 8

Southern Company's net investment in international leveraged leases consists of the following at December 31:

	2010	2009
	(in millions)	
Net rentals receivable	**$ 733**	$ 734
Unearned income	**(377)**	(393)
Investment in leveraged leases	**356**	341
Current taxes payable	**-**	-
Deferred taxes from leveraged leases	**(40)**	(40)
Net investment in leveraged leases	**$ 316**	$ 301

A summary of the components of income from international leveraged leases was as follows:

	2010	2009	2008
		(in millions)	
Pretax leveraged lease income (loss)	**$14**	$19	$(99)
Income tax benefit (expense)	**(5)**	(7)	35
Net leveraged lease income (loss)	**$ 9**	$12	$(64)

The Company terminated two international leveraged lease investments during 2009. The proceeds were used to extinguish all debt related to leveraged lease investments, a portion of which had make-whole redemption provisions. This resulted in a $17 million loss which partially offset a $26 million gain on the terminations.

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 costs 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 traditional operating companies through fuel cost recovery rates approved by each state PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

Southern Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of Southern Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional operating companies' fuel hedging programs. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2010, the amount included in accounts payable in the balance sheets that the Company has recognized for the obligation to return cash collateral arising from derivative instruments was not material.

Southern 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 marketable securities, certain changes in pension and other postretirement benefit plans, and reclassifications for amounts included in net income.

Accumulated OCI (loss) balances, net of tax effects, were as follows:

	Qualifying Hedges	Marketable Securities	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
			(in millions)	
Balance at December 31, 2009	$(49)	$10	$(49)	$ (88)
Current period change	14	(3)	7	18
Balance at December 31, 2010	**$(35)**	**$ 7**	**$(42)**	**$ (70)**

Variable Interest Entities

Effective January 1, 2010, the traditional operating companies and Southern Power adopted new accounting guidance which modified the consolidation model and expanded disclosures related to variable interest entities (VIE). The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. The adoption of this new accounting guidance did not result in the traditional operating companies or Southern Power consolidating any VIEs that were not already consolidated under previous guidance, nor deconsolidating any VIEs.

Certain of the traditional operating companies have established certain wholly-owned trusts to issue preferred securities. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information. However, Southern Company and the applicable traditional operating companies are not considered the primary beneficiaries of the trusts. Therefore, the investments in these trusts are reflected as other investments, and the related loans from the trusts are reflected in long-term debt in the balance sheets.

2. RETIREMENT BENEFITS

Southern 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 traditional operating companies and certain other subsidiaries contributed approximately $620 million to the qualified pension plan. No contributions to the qualified pension plan are expected for the year ending December 31, 2011. Southern 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, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2011, other postretirement trust contributions are expected to total approximately $31 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 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	**5.52%**	5.93%	6.75%
Other postretirement benefit plans	**5.40**	5.83	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	**7.40**	7.51	7.59

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 5.0% 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 millions)	
Benefit obligation	$128	$108
Service and interest costs	7	6

Pension Plans

The total accumulated benefit obligation for the pension plans was $6.7 billion in 2010 and $6.3 billion 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 millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$6,758**	$5,879
Service cost	**172**	146
Interest cost	**391**	387
Benefits paid	**(296)**	(282)
Actuarial loss (gain)	**198**	628
Balance at end of year	**7,223**	6,758
Change in plan assets		
Fair value of plan assets at beginning of year	**5,627**	5,093
Actual return (loss) on plan assets	**859**	792
Employer contributions	**644**	24
Benefits paid	**(296)**	(282)
Fair value of plan assets at end of year	**6,834**	5,627
Accrued liability	**$ (389)**	$(1,131)

At December 31, 2010, the projected benefit obligations for the qualified and non-qualified pension plans were $6.7 billion and $0.5 billion, 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 millions)	
Prepaid pension costs	**$ 88**	$ -
Other regulatory assets, deferred	**1,749**	1,894
Other current liabilities	**(28)**	(25)
Employee benefit obligations	**(449)**	(1,106)
Accumulated OCI	**68**	74

Presented below are the amounts included in accumulated OCI and 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.

	Prior Service Cost	**Net (Gain) Loss**
	(in millions)	
Balance at December 31, 2010:		
Accumulated OCI	**$ 8**	**$ 60**
Regulatory assets	**159**	**1,590**
Total	**$ 167**	**$ 1,650**
Balance at December 31, 2009:		
Accumulated OCI	$ 10	$ 64
Regulatory assets	188	1,706
Total	$198	$1,770
Estimated amortization in net periodic pension cost in 2011:		
Accumulated OCI	$ 1	$ 1
Regulatory assets	31	20
Total	$32	$21

The components of OCI and 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:

	Accumulated OCI	**Regulatory Assets**
	(in millions)	
Balance at December 31, 2008	$54	$1,579
Net loss	21	355
Change in prior service costs	-	1
Reclassification adjustments:		
Amortization of prior service costs	(1)	(34)
Amortization of net gain	-	(7)
Total reclassification adjustments	(1)	(41)
Total change	20	315
Balance at December 31, 2009	74	1,894
Net gain	**(4)**	**(106)**
Change in prior service costs	**-**	**2**
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	**(32)**
Amortization of net gain	**(1)**	**(9)**
Total reclassification adjustments	**(2)**	**(41)**
Total change	**(6)**	**(145)**
Balance at December 31, 2010	**$ 68**	**$1,749**

Components of net periodic pension cost were as follows:

	2010	2009	2008
		(in millions)	
Service cost	**$ 172**	$ 146	$ 146
Interest cost	**391**	387	348
Expected return on plan assets	**(552)**	(541)	(525)
Recognized net loss	**10**	7	9
Net amortization	**33**	35	37
Net periodic pension cost	**$ 54**	$ 34	$ 15

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 millions)
2011	$ 335
2012	353
2013	372
2014	392
2015	413
2016 to 2020	2,368

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 millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$1,759**	$1,733
Service cost	**25**	26
Interest cost	**100**	113
Benefits paid	**(95)**	(93)
Actuarial loss (gain)	**(41)**	34
Plan amendments	**(2)**	(59)
Retiree drug subsidy	**6**	5
Balance at end of year	**1,752**	1,759
Change in plan assets		
Fair value of plan assets at beginning of year	**743**	631
Actual return (loss) on plan assets	**82**	127
Employer contributions	**66**	72
Benefits paid	**(89)**	(87)
Fair value of plan assets at end of year	**802**	743
Accrued liability	**$ (950)**	$(1,016)

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 millions)	
Other regulatory assets, deferred	**$ 292**	$ 374
Other current liabilities	**(1)**	-
Employee benefit obligations	**(949)**	(1,016)
Accumulated OCI	**3**	5

Presented below are the amounts included in accumulated OCI and 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.

	Prior Service Cost	Net (Gain) Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2010:			
Accumulated OCI	**$ -**	**$ 3**	**$ -**
Regulatory assets	**34**	**233**	**25**
Total	**$34**	**$236**	**$25**
Balance at December 31, 2009:			
Accumulated OCI	$ -	$ 5	$ -
Regulatory assets	41	298	35
Total	$41	$303	$35
Estimated amortization as net periodic postretirement benefit cost in 2011:			
Accumulated OCI	$ -	$ -	$ -
Regulatory assets	5	4	10
Total	$ 5	$ 4	$10

The components of OCI, along with the changes in the balance of regulatory assets, related to the other postretirement benefit plans for the plan years ended December 31, 2010 and 2009 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2008	$8	$489
Net gain	-	(33)
Change in prior service costs/transition obligation	(3)	(56)
Reclassification adjustments:		
Amortization of transition obligation	-	(13)
Amortization of prior service costs	-	(8)
Amortization of net gain	-	(5)
Total reclassification adjustments	-	(26)
Total change	(3)	(115)
Balance at December 31, 2009	5	374
Net gain	**(2)**	**(60)**
Change in prior service costs/transition obligation	**-**	**(2)**
Reclassification adjustments:		
Amortization of transition obligation	**-**	**(10)**
Amortization of prior service costs	**-**	**(5)**
Amortization of net gain	**-**	**(5)**
Total reclassification adjustments	**-**	**(20)**
Total change	**(2)**	**(82)**
Balance at December 31, 2010	**$3**	**$292**

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

	2010	2009	2008
		(in millions)	
Service cost	**$ 25**	$ 26	$ 28
Interest cost	**100**	113	111
Expected return on plan assets	**(63)**	(61)	(59)
Net amortization	**20**	25	31
Net postretirement cost	**$ 82**	$103	$111

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 Southern Company's expenses for the years ended December 31, 2010, 2009, and 2008 by approximately $28 million, $33 million, and $35 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 millions)	
2011	$108	$ (8)	$100
2012	114	(9)	105
2013	121	(10)	111
2014	127	(12)	115
2015	133	(13)	120
2016 to 2020	695	(69)	626

Benefit Plan Assets

Pension plan and other postretirement 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 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	42%	**40%**	37%
International equity	18	**21**	24
Domestic fixed income	27	**29**	32
Global fixed income	4	**3**	-
Special situations	1	**-**	-
Real estate investments	5	**4**	4
Private equity	3	**3**	3
Total	100%	**100%**	100%

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

Investment Strategies

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

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance.*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** 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 millions)		
Assets:				
Domestic equity*	$1,266	$511	$1	$1,778
International equity*	1,277	443	-	1,720
Fixed income:				
U.S. Treasury, government, and agency bonds	-	304	-	304
Mortgage- and asset-backed securities	-	247	-	247
Corporate bonds	-	594	2	596
Pooled funds	-	201	-	201
Cash equivalents and other	2	478	-	480
Special situations	-	-	-	-
Real estate investments	184	-	674	858
Private equity	-	-	638	638
Total	$2,729	$2,778	$1,315	$6,822
Liabilities:				
Derivatives	(1)	-	-	(1)
Total	$2,728	$2,778	$1,315	$6,821

*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 millions)		
Assets:				
Domestic equity*	$1,117	$462	$ -	$1,579
International equity*	1,444	144	-	1,588
Fixed income:				
U.S. Treasury, government, and agency bonds	-	416	-	416
Mortgage- and asset-backed securities	-	113	-	113
Corporate bonds	-	279	-	279
Pooled funds	-	10	-	10
Cash equivalents and other	3	341	-	344
Special situations	-	-	-	-
Real estate investments	174	-	547	721
Private equity	-	-	555	555
Total	$2,738	$1,765	$1,102	$5,605
Liabilities:				
Derivatives	(5)	(1)	-	(6)
Total	$2,733	$1,764	$1,102	$5,599

*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 were as follows:

	2010		2009	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in millions)		
Beginning balance	**$547**	**$555**	$ 839	$490
Actual return on investments:				
Related to investments held at year end	**59**	**67**	(240)	37
Related to investments sold during the year	**18**	**18**	(65)	10
Total return on investments	**77**	**85**	(305)	47
Purchases, sales, and settlements	**50**	**(2)**	13	18
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$674**	**$638**	$ 547	$555

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 millions)		
Assets:				
Domestic equity*	$176	$45	$ -	$221
International equity*	49	50	-	99
Fixed income:				
U.S. Treasury, government, and agency bonds	-	15	-	15
Mortgage- and asset-backed securities	-	10	-	10
Corporate bonds	-	23	-	23
Pooled funds	-	34	-	34
Cash equivalents and other	-	41	-	41
Trust-owned life insurance	-	291	-	291
Special situations	-	-	-	-
Real estate investments	7	-	26	33
Private equity	-	-	23	23
Total	$232	$509	$49	$790

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

	Fair Value Measurements Using			
As of December 31, 2009:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$149	$42	$-	$191
International equity*	62	36	-	98
Fixed income:				
U.S. Treasury, government, and agency bonds	-	22	-	22
Mortgage- and asset-backed securities	-	5	-	5
Corporate bonds	-	12	-	12
Pooled funds	-	18	-	18
Cash equivalents and other	-	54	-	54
Trust-owned life insurance	-	270	-	270
Special situations	-	-	-	-
Real estate investments	7	-	24	31
Private equity	-	-	24	24
Total	$218	$459	$48	$725

*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 were as follows:

	2010		2009	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in millions)			
Beginning balance	**$24**	**$24**	$36	$21
Actual return on investments:				
Related to investments held at year end	**2**	**1**	(10)	2
Related to investments sold during the year	**-**	**-**	(3)	-
Total return on investments	**2**	**1**	(13)	2
Purchases, sales, and settlements	**-**	**(2)**	1	1
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$26**	**$23**	$24	$24

Employee Savings Plan

Southern 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 $76 million, $78 million, and $76 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the business activities of Southern Company's subsidiaries 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 Southern Company and its subsidiaries 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 Southern 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. 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 facilities co-owned by Mississippi Power and Gulf Power. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The EPA concurrently issued notices of violation to Gulf Power and Mississippi Power relating to Gulf Power's Plant Crist and Mississippi Power's Plant Watson. In early 2000, the EPA filed a motion to amend its complaint to add Gulf Power and Mississippi Power as defendants based on the allegations in the notices of violation. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not re-filed. The original action, now solely against Georgia Power, has been administratively closed since the spring of 2001, and the case has not been reopened. The separate action against Alabama Power is ongoing.

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, including the claim relating to a facility co-owned by Mississippi Power. 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.

Southern Company believes that the traditional operating companies 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

Southern Company's subsidiaries 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 subsidiaries may also incur substantial costs to clean up properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. Within limits approved by the state PSCs, these rates are adjusted annually or as necessary.

Georgia Power's environmental remediation liability as of December 31, 2010 was $13 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and CERCLA NPL are anticipated.

In September 2008, the EPA advised Georgia Power that it has been designated as a PRP at the Ward Transformer Superfund site located in Raleigh, North Carolina. Numerous other entities have also received notices regarding this site from the EPA. Georgia Power, along with other named PRPs, is negotiating with the EPA to address cleanup of the site and reimbursement for past expenditures related to work performed at the site. In addition, in April 2009, two PRPs filed separate actions in the U.S. District Court for the Eastern District of North Carolina against numerous other PRPs, including Georgia Power, seeking contribution from the defendants for expenses incurred by the plaintiffs related to work performed at a portion of the site. The ultimate outcome of these matters will depend upon further environmental assessment and the ultimate number of PRPs and cannot be determined at this time; however, it is not expected to have a material impact on Southern Company's financial statements.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $62 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 Gulf Power 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 Gulf Power's environmental cost recovery clause; therefore, there was no impact on net income as a result of these estimates.

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, management does not believe that additional liabilities, if any, at these sites would be material to the financial statements.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including Mississippi Power, have been named as defendants in numerous lawsuits brought by landowners since 2001. The plaintiffs' lawsuits claim that defendants may not use, or sublease to third parties, some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties and that such actions exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment and seek compensatory and punitive damages and injunctive relief. Management of Southern Company believes that its subsidiaries have complied with applicable laws and that the plaintiffs' claims are without merit.

Mississippi Power has entered into agreements with plaintiffs in approximately 95% of the actions pending against Mississippi Power to clarify its easement rights in the State of Mississippi. These agreements have been approved by the Circuit Courts of Harrison County and Jasper County, Mississippi (First Judicial Circuit), and the related cases have been dismissed. These agreements have not resulted in any material effects on Southern Company's financial statements.

In addition, in late 2001, certain subsidiaries of Southern Company, including Mississippi Power, were named as defendants in a lawsuit brought in Troup County, Georgia, Superior Court by Interstate Fiber Network Inc. a subsidiary of telecommunications company ITC DeltaCom, Inc. that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. On August 24, 2010, the defendants filed a motion to dismiss the suit for lack of prosecution. In January 2011, the court indicated that it intended to deny the defendant's motion to dismiss the claim; however, no written order denying the motion has been entered into the record. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Nuclear Fuel Disposal Costs

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

In July 2007, the U.S. Court of Federal Claims awarded Georgia Power approximately $30 million, based on its ownership interests, and awarded Alabama Power approximately $17 million, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plants Farley, Hatch, and Vogtle from 1998 through 2004. In November 2007, the government's motion for reconsideration was denied. In January 2008, the government filed an appeal and, in February 2008, filed a motion to stay the appeal, which the U.S. Court of Appeals for the Federal Circuit granted in April 2008. On May 5, 2010, the U.S. Court of Appeals for the Federal Circuit lifted the stay.

In April 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim), due to the government's alleged continuing breach of contract. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2010 for either claim. The final outcome of these matters cannot be determined at this time, but no material impact on net income is expected as any damage amounts collected from the government are expected to be returned to customers.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plants Hatch and Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of each plant.

Income Tax Matters

Georgia State Income Tax Credits

Georgia Power's 2005 through 2009 income tax filings for the State of Georgia include state income tax credits for increased activity through Georgia ports. Georgia Power also filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue (DOR) has not responded to these claims. In July 2007, Georgia Power filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On March 22, 2010, the Superior Court of Fulton County ruled in favor of Georgia Power's motion for summary judgment. The Georgia DOR has appealed to the Georgia Court of Appeals and a decision is expected later this year. Any decision may be subject to further appeal to the Georgia Supreme Court. An unrecognized tax benefit has been recorded related to these credits. If Georgia Power prevails, no material impact on Southern Company's net income is expected as a significant portion of any tax benefit is expected to be returned to retail customers in accordance with the Georgia PSC - approved Alternate Rate Plan for Georgia Power which became effective January 1, 2011 and will continue through December 31, 2013 (the 2010 ARP). If Georgia Power is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on Southern Company's cash flow. See Note 5 under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot now be determined.

Tax Method of Accounting for Repairs

Southern Company submitted a change in the tax accounting method for repair costs associated with Southern Company's generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. On a consolidated basis, the new tax method resulted in net positive cash flow in 2010 of approximately $297 million. Although Internal Revenue Service (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

Alabama Power

Rate RSE

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

The Rate RSE increase for 2010 was 3.24%, or $152 million annually, and was effective in January 2010. In December 2010, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2011 and earnings were within the specified return range. Consequently, the retail rates will remain unchanged in 2011 under Rate RSE. Under the terms of Rate RSE, the maximum increase for 2012 cannot exceed 5.00%.

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated power purchase agreements (PPA) under Rate CNP. There was no adjustment to the Rate CNP to recover certificated PPA costs in 2008 or 2009. Effective April 2010, rate certificated new plant (Rate CNP) was reduced by approximately $70 million annually, primarily due to the expiration on May 31, 2010, of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. It is estimated that there will be a slight decrease to the current Rate CNP effective April 2011.

Rate CNP also allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Retail rates increased approximately 2.4% in January 2008 and 4.3% in January 2010 due to environmental costs. In October 2008, Alabama Power agreed to defer collection of any increase in rates under this portion of Rate CNP, which permits recovery of costs associated with environmental laws and regulations, from 2009 until 2010. The deferral of the retail rate adjustments had an immaterial impact on annual cash flows, and had no significant effect on the Company's revenues or net income. On December 1, 2010, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflects an incremental increase in the revenue requirement associated with such environmental compliance, which would be recoverable in the billing months of January 2011 through December 2011. In order to afford additional rate stability to customers as the economy continues to recover from the recession, the Alabama PSC ordered on January 4, 2011 that Alabama Power leave in effect for 2011 the factors associated with Alabama Power's environmental compliance costs for the year 2010. Any recoverable amounts associated with 2011 will be reflected in the 2012 filing. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

Alabama Power has established fuel cost recovery rates under Alabama Power's energy cost recovery rate mechanism (Rate ECR) as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. Alabama Power, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per kilowatt hour (KWH). The Rate ECR factor as of January 1, 2011 is 2.403 cents per KWH. Effective with billings beginning in April 2011, the Rate ECR factor will be 2.681 cents per KWH.

As of December 31, 2010, Alabama Power had an under recovered fuel balance of approximately $4 million which is included in deferred under recovered regulatory clause revenues in the balance sheets. As of December 31, 2009, Alabama Power had an over recovered fuel balance of approximately $200 million of which approximately $22 million was included in deferred over recovered regulatory clause revenues in the balance sheets. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any return of the over recovered fuel costs or recovery of under recovered fuel costs.

Natural Disaster Reserve

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

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

On August 20, 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows Alabama Power to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance Alabama Power’s ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

For the year ended December 31, 2010, Alabama Power accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. For the year ended December 31, 2009, Alabama Power accrued an additional $40 million to the NDR, resulting in an accumulated balance of approximately $75 million. These accruals are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

Georgia Power

Retail Rate Plans

The economic recession significantly reduced Georgia Power’s revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 (the 2007 Retail Rate Plan). In June 2009, despite stringent efforts to reduce expenses, Georgia Power’s projected retail ROE for both 2009 and 2010 was below 10.25%. However, in lieu of filing to increase customer rates as allowed under the 2007 Retail Rate Plan, in June 2009, Georgia Power filed a request with the Georgia PSC for an accounting order that would allow Georgia Power to amortize up to $324 million of its regulatory liability related to other cost of removal obligations.

In August 2009, the Georgia PSC approved the accounting order. Under the terms of the accounting order, Georgia Power could amortize up to $108 million of the regulatory liability in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, Georgia Power amortized $41 million and $174 million of the regulatory liability, respectively.

On December 21, 2010, the Georgia PSC approved an Alternate Rate Plan for Georgia Power which became effective January 1, 2011 and continuing through December 31, 2013 (the 2010 ARP). The terms of the 2010 ARP reflect a settlement agreement among Georgia Power, the Georgia PSC’s Public Interest Advocacy Staff (PSC Staff) and eight other intervenors. Under the terms of the 2010 ARP, Georgia Power will amortize approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

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

Under the 2010 ARP, the following additional base rate adjustments will be made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs will increase by $17 million;
- Effective April 1, 2012, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4 and 5 for the period from commercial operation through December 31, 2013;
- Effective January 1, 2013, the DSM tariffs will increase by $18 million;
- Effective January 1, 2013, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Unit 6 for the period from commercial operation through December 31, 2013; and
- The MFF tariff will increase consistent with these adjustments.

Georgia Power currently estimates these adjustments will result in annualized base revenue increases of approximately $190 million in 2012 and $93 million in 2013.

Under the 2010 ARP, Georgia Power's retail ROE is set at 11.15% and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. If at any time during the term of the 2010 ARP, Georgia Power projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust Georgia Power's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, Georgia Power may file a full rate case.

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

Georgia Power currently expects to file an update to its integrated resource plan (IRP) in June 2011. Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets (resulting from new or revised environmental regulations) through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. Such costs that may be deferred as a regulatory asset include any impairment losses that may result from a decision to retire certain units that are no longer cost effective in light of new or modified environmental regulations. In addition, in connection with the 2010 ARP, the Georgia PSC also approved revised depreciation rates that will recover the remaining book value of certain of Georgia Power's existing coal-fired units by December 31, 2014.

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

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved increases in Georgia Power's total annual billings of approximately $222 million effective June 1, 2008 and $373 million effective April 1, 2010. In addition, the Georgia PSC has authorized an interim fuel rider, which would allow Georgia Power to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds budget by more than $75 million. Georgia Power is currently required to file its next fuel case by March 1, 2011.

As of December 31, 2010, Georgia Power's under recovered fuel balance totaled approximately $398 million, of which approximately $214 million is included in deferred charges and other assets in the balance sheets.

Fuel cost recovery revenues as recorded in the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, a change in the billing factor has no significant effect on Southern Company's revenues or net income, but does impact annual cash flow.

Nuclear Construction

In August 2009, the NRC issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of Georgia Power, Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light and Sinking Fund Commissioners (collectively, Owners), related to two additional nuclear units on the site of Plant Vogtle (Plant Vogtle Units 3 and 4). See Note 4 for additional information on these co-owners. In March 2008, Southern Nuclear filed an application with the NRC for a combined construction and operating license (COL) for the new units. If licensed by the NRC, Plant Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively.

In April 2008, Georgia Power, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts (MWs) each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share is 45.7%.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COL or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In March 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve inclusion of the related construction work in progress accounts in rate base. In April 2009, the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows Georgia Power to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allows Georgia Power to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. The Georgia PSC has ordered Georgia Power to report against this total certified cost of approximately $6.1 billion. In addition, on December 21, 2010, the Georgia PSC approved Georgia Power's Nuclear Construction Cost Recovery (NCCR) tariff. The NCCR tariff became effective January 1, 2011 and is expected to collect approximately $223 million in revenues during 2011.

On February 21, 2011, the Georgia PSC voted to approve Georgia Power's third semi-annual construction monitoring report including total costs of $1.048 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2010. In connection with its certification of Plant Vogtle Units 3 and 4, the Georgia PSC ordered Georgia Power and the PSC Staff to work together to develop a risk sharing or incentive mechanism that would provide some level of protection to ratepayers in the event of significant cost overruns, but also not penalize Georgia Power's earnings if and when overruns are due to mandates from governing agencies. Such discussions have continued through the third semi-annual construction monitoring proceedings; however, the Georgia PSC has deferred a decision with respect to any related incentive or risk-sharing mechanism until a later date. Georgia Power will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In 2009, the Southern Alliance for Clean Energy (SACE) and the Fulton County Taxpayers Foundation, Inc. (FCTF) filed separate petitions in the Superior Court of Fulton County, Georgia seeking review of the Georgia PSC's certification order and challenging the constitutionality of the Georgia Nuclear Energy Financing Act. On May 5, 2010, the court dismissed as premature the plaintiffs' claim challenging the Georgia Nuclear Energy Financing Act. FCTF appealed the decision, and the Georgia Supreme Court ruled against FCTF, finding the suit premature. In addition, on May 5, 2010, the Superior Court of Fulton County issued an order remanding the Georgia PSC's certification order for inclusion of further findings of fact and conclusions of law by the Georgia PSC. In compliance with the court's order, the Georgia PSC issued its order on remand to include further findings of fact and conclusions of law on June 23, 2010. On July 5, 2010, SACE and FCTF filed separate motions with the Georgia PSC for reconsideration of the order on remand. On August 17, 2010, the Georgia PSC voted to reaffirm its order. The matter is no longer subject to judicial review and is now concluded.

On December 2, 2010, Westinghouse submitted an AP1000 Design Certification Amendment (DCA) to the NRC. On February 10, 2011, the NRC announced that it was seeking public comment on a proposed rule to approve the DCA and amend the certified AP1000 reactor design for use in the U.S. The Advisory Committee on Reactor Safeguards also issued a letter on January 24, 2011 endorsing the issuance of the COL for Plant Vogtle Units 3 and 4. Georgia Power currently expects to receive the COL for Plant Vogtle Units 3 and 4 from the NRC in late 2011 based on the NRC's February 16, 2011 release of its COL schedule framework.

There are other pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4. Similar additional challenges at the state and federal level are expected as construction proceeds.

The ultimate outcome of these matters cannot now be determined.

Other Construction

On May 6, 2010, the Georgia PSC approved Georgia Power's request to extend the construction schedule for Plant McDonough Units 4, 5, and 6 as a result of the short-term reduction in forecasted demand, as well as the requested increase in the certified amount. As a result, the units are expected to be placed into service in January 2012, May 2012, and January 2013, respectively. The Georgia PSC has approved Georgia Power's quarterly construction monitoring reports, including actual project expenditures incurred, through June 30, 2010. Georgia Power will continue to file quarterly construction monitoring reports throughout the construction period.

Mississippi Power Integrated Coal Gasification Combined Cycle

In January 2009, Mississippi Power filed for a Certificate of Public Convenience and Necessity (CPCN) with the Mississippi PSC to allow the acquisition, construction, and operation of a new electric generating plant located in Kemper County, Mississippi that would utilize an integrated coal gasification combined cycle (IGCC) technology with an output capacity of 582 MWs. The estimated cost of the plant is $2.4 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (CCPI2). The plant will use locally mined lignite (an abundant, lower heating value coal) from a proposed mine adjacent to the plant as fuel. In conjunction with the Kemper IGCC, Mississippi Power will own a lignite mine and equipment and will acquire mineral reserves located around the plant site in Kemper County. The estimated capital cost of the mine is approximately $214 million. On May 27, 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC, a subsidiary of The North American Coal Corporation, which will develop, construct, and manage the mining operations. The agreement is effective June 1, 2010 through the end of the mine reclamation. The plant, subject to federal and state reviews and certain regulatory approvals, is expected to begin commercial operation in May 2014.

On April 29, 2010, the Mississippi PSC issued an order finding that Mississippi Power's application to acquire, construct, and operate the plant did not satisfy the requirement of public convenience and necessity in the form that the project and the related cost recovery were originally proposed by Mississippi Power, unless Mississippi Power accepted certain conditions on the issuance of the CPCN, including a cost cap of approximately $2.4 billion. Following additional proceedings, on May 26, 2010, the Mississippi PSC issued an order revising its findings from the April 29, 2010 order. Among other things, the Mississippi PSC's May 26, 2010 order (1) approved an alternate construction cost cap of up to $2.88 billion (and any amounts that fall within specified exemptions from the cost cap; such exemptions include the cost of the lignite mine and equipment and the carbon dioxide pipeline facilities), subject to determinations by the Mississippi PSC that such costs in excess of $2.4 billion are prudent and required by the public convenience and necessity; (2) provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's proposal; (3) approved financing cost recovery on construction work in progress (CWIP) balances, which provides for the accrual of AFUDC in 2010 and 2011 and recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of CWIP allowed is (i) reduced by the amount of state and federal government construction cost incentives received by Mississippi Power in excess of $296 million to the extent that such amount increases cash flow for the pertinent regulatory period and (ii) justified by a showing that such CWIP allowance will benefit customers over the life of the plant). The Mississippi PSC order established periodic prudence reviews during the annual CWIP review process. More frequent prudence determinations may be requested at a later time. On May 27, 2010, Mississippi Power filed a motion with the Mississippi PSC accepting the conditions contained in the order. On June 3, 2010, the Mississippi PSC issued the CPCN for the Kemper IGCC.

On August 19, 2010, the National Environmental Policy Act (NEPA) Record of Decision (ROD) by the DOE for Mississippi Power's CCPI2 grants was noted in the Federal Register. The NEPA ROD and its accompanying final environmental impact statement were the final major hurdles necessary for Mississippi Power to receive grand funds of $245 million during the construction of the plant and $25 million during the initial operation of the Kemper IGCC. As of December 31, 2010, Mississippi Power has received $23 million and billed an additional $9 million associated with this grant.

In April 2009, the Governor of the State of Mississippi signed into law a bill that will provide an ad valorem tax exemption for a portion of the assessed value of all property utilized in certain electric generating facilities with integrated gasification process facilities. This tax exemption, which may not exceed 50% of the total value of the project, is for projects with a capital investment from private sources of $1 billion or more. Mississippi Power expects the Kemper IGCC, including the gasification portion, to be a qualifying project under the law.

On June 17, 2010, the Mississippi Chapter of the Sierra Club (Sierra Club) filed an appeal of the Mississippi PSC's June 3, 2010 decision to grant the CPCN for the Kemper IGCC with the Chancery Court of Harrison County, Mississippi (Chancery Court). On December 22, 2010, the Chancery Court denied Mississippi Power's motion to dismiss the suit. A decision on the Sierra Club's appeal from the Chancery Court is expected in March 2011. In addition, in a separate proceeding, the Sierra Club has requested an evidentiary hearing regarding the issuance of a modified Prevention of Significant Deterioration air permit for the Kemper IGCC.

Mississippi Power has been awarded certain tax credits available to projects using clean and advance coal technologies under the Energy Policy Act of 2005 (Phase I tax credits) and under the Energy Improvement and Extension Act of 2008 (Phase II tax credits). In November 2006, the IRS allocated $133 million of Phase I tax credits to Mississippi Power and in April 2010, the IRS allocated $279 million of Phase II tax credits to Mississippi Power. The utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 2014 for the Phase I credits. In order to remain eligible for the Phase II tax credits, Mississippi Power must also capture and sequester at least 65% of the carbon dioxide produced by the plant during operations in accordance with recapture rules for Section 48A tax credits. Through December 31, 2010, Mississippi Power received tax benefits of $22 million for these tax credits.

In February 2008, Mississippi Power requested that the DOE transfer the remaining funds previously granted under the CCPI2 from a cancelled IGCC project of one of Southern Company's affiliates that would have been located in Orlando, Florida. In December 2008, an agreement was reached to assign the remaining funds ($270 million) to the Kemper IGCC.

On July 27, 2010, Mississippi Power and South Mississippi Electric Power Association (SMEPA) entered into an Asset Purchase Agreement whereby SMEPA will purchase a 17.5% undivided ownership interest in the Kemper IGCC. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. On December 2, 2010, Mississippi Power and SMEPA filed a joint petition with the Mississippi PSC requesting regulatory approval for SMEPA's 17.5% ownership of the Kemper IGCC.

The Mississippi PSC has issued orders allowing Mississippi Power to defer the costs associated with the generation resource planning, evaluation, and screening activities for the Kemper IGCC as a regulatory asset. In addition, on November 12, 2010, Mississippi Power filed a petition with the Mississippi PSC requesting an accounting order that would establish regulatory assets for certain non-capital costs related to the Kemper IGCC. In its petition, Mississippi Power outlined three categories of non-capital, plant-related costs that it proposed to defer in a regulatory asset until construction is complete and a cost recovery mechanism is established for the Kemper IGCC: (1) regulatory costs; (2) cost of executing nonconstruction contracts; and (3) other project-related costs not permitted to be capitalized.

As of December 31, 2010, Mississippi Power had spent a total of $255 million on the Kemper IGCC, including regulatory filing costs. Of this total, $208 million was included in CWIP (net of $33 million of CCPI2 grant funds), $12 million was recorded in other regulatory assets, $2 million was recorded in other deferred charges and assets, and $1 million was previously expensed.

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

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in units 1 and 2 of Plant Miller and related facilities jointly with Power South Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with OPC, MEAG Power, the City of Dalton, Georgia, Florida Power & Light Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities and with Florida Power Corporation for a combustion turbine unit at Intercession City, Florida. Southern Power owns an undivided interest in Plant Stanton Unit A and related facilities jointly with the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency.

At December 31, 2010, Alabama Power's, Georgia Power's, and Southern Power's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation with the above entities were as follows:

	Percent Ownership	Amount of Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)			
Units 1 and 2	45.7%	$3,292	$1,935
Plant Hatch (nuclear)	50.1	962	534
Plant Miller (coal)			
Units 1 and 2	91.8	1,253	477
Plant Scherer (coal)			
Units 1 and 2	8.4	148	74
Plant Wansley (coal)	53.5	700	208
Rocky Mountain (pumped storage)	25.4	175	109
Intercession City (combustion turbine)	33.3	12	3
Plant Stanton (combined cycle)			
Unit A	65.0	156	25

At December 31, 2010, the portion of total construction work in progress related to Plants Miller, Scherer, Wansley, and Vogtle Units 3 and 4 was $125 million, $110 million, $11 million, and $1.3 billion, respectively. Construction at Plants Miller, Wansley, and Scherer relates primarily to environmental projects. See Note 3 under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for information on Plant Vogtle Units 3 and 4.

Alabama Power, Georgia Power, and Southern Power have contracted to operate and maintain the jointly owned facilities, except for Rocky Mountain and Intercession City, as agents for their respective co-owners. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income and each company is responsible for providing its own financing.

5. INCOME TAXES

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

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2010	2009	2008
		(in millions)	
Federal –			
Current	**$ 42**	$771	$628
Deferred	**898**	40	177
	940	811	805
State –			
Current	**(54)**	100	72
Deferred	**140**	(15)	38
	86	85	110
Total	**$1,026**	$896	$915

Net cash payments for income taxes in 2010, 2009, and 2008 were $276 million, $975 million, and $537 million, respectively.

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 millions)	
Deferred tax liabilities –		
Accelerated depreciation	**$6,833**	$5,938
Property basis differences	**1,150**	986
Leveraged lease basis differences	**263**	251
Employee benefit obligations	**485**	384
Under recovered fuel clause	**179**	271
Premium on reacquired debt	**78**	100
Regulatory assets associated with employee benefit obligations	**814**	939
Regulatory assets associated with asset retirement obligations	**509**	486
Other	**246**	216
Total	**10,557**	9,571
Deferred tax assets –		
Federal effect of state deferred taxes	**386**	302
State effect of federal deferred taxes	**50**	108
Employee benefit obligations	**1,179**	1,435
Over recovered fuel clause	**40**	119
Other property basis differences	**119**	132
Deferred costs	**100**	65
Cost of removal	**52**	109
Unbilled revenue	**126**	96
Other comprehensive losses	**69**	81
Asset retirement obligations	**509**	486
Other	**523**	458
Total	**3,153**	3,391
Total deferred tax liabilities, net	**7,404**	6,180
Portion included in prepaid expenses (accrued income taxes), net	**117**	229
Deferred state tax assets	**91**	105
Valuation allowance	**(58)**	(59)
Accumulated deferred income taxes	**$7,554**	$6,455

At December 31, 2010, Southern Company had a State of Georgia net operating loss (NOL) carryforward totaling $0.9 billion, which could result in net state income tax benefits of $53 million, if utilized. However, Southern Company has established a valuation allowance for the potential $53 million tax benefit due to the remote likelihood that the tax benefit will be realized. These NOLs expire between 2011 and 2021. Beginning in 2002, the State of Georgia allowed Southern Company to file a combined return, which has prevented the creation of any additional NOL carryforwards.

At December 31, 2010, the tax-related regulatory assets and liabilities were $1.3 billion and $237 million, respectively. 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 interest. In 2010, $82 million was deferred as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of healthcare costs that are covered by federal Medicare subsidy payments. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $23 million in 2010, $24 million in 2009, and $23 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 tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2010	2009	2008
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**1.8**	2.1	2.6
Employee stock plans dividend deduction	**(1.2)**	(1.4)	(1.3)
Non-deductible book depreciation	**0.8**	0.9	0.8
Difference in prior years' deferred and current tax rate	**(0.1)**	(0.1)	(0.2)
AFUDC-Equity	**(2.2)**	(2.7)	(1.9)
Production activities deduction	**-**	(0.7)	(0.4)
ITC basis difference	**(0.4)**	-	-
Leveraged lease termination	**-**	(0.9)	-
MC Asset Recovery	**-**	2.7	-
Donations	**-**	(0.4)	-
Other	**(0.2)**	(0.1)	(1.0)
Effective income tax rate	**33.5%**	34.4%	33.6%

Southern Company's effective tax rate is lower than the statutory rate primarily due to the employee stock plans' dividend deduction and AFUDC equity, which is not taxable.

Southern Company's 2010 effective tax rate decreased from 2009 primarily due to the $202 million charge recorded for the MC Asset Recovery litigation settlement in 2009, which completed and resolved all claims by MC Asset Recovery against Southern Company. Southern Company is currently evaluating potential recovery of the settlement payment through various means including insurance, claims in U.S. Bankruptcy Court, and other avenues. The degree to which any recovery is realized will determine, in part, the final income tax treatment of the settlement payment. The ultimate outcome of any such recovery and/or income tax treatment cannot be determined at this time. The decrease in Southern Company's effective tax rate was partially offset by the elimination of the production activities deduction in 2010.

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The 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 Southern 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 Southern Company for 2010.

Unrecognized Tax Benefits

For 2010, the total amount of unrecognized tax benefits increased by $97 million, resulting in a balance of $296 million as of December 31, 2010.

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

	2010	2009	2008
		(in millions)	
Unrecognized tax benefits at beginning of year	**$199**	$146	$264
Tax positions from current periods	**62**	53	49
Tax positions increase from prior periods	**62**	12	130
Tax positions decrease from prior periods	**(27)**	(10)	-
Reductions due to settlements	**-**	-	(297)
Reductions due to expired statute of limitations	**-**	(2)	-
Balance at end of year	**$296**	$199	$146

The tax positions from current periods relate primarily to the Georgia state tax credits litigation, tax accounting method change for repairs, 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 positions. The tax positions decrease from prior periods relates primarily to the Georgia state tax credit litigation and miscellaneous tax positions. See Note 3 under "Income Tax Matters – Georgia State Income Tax Credits" and "Tax Method of Accounting for Repairs" for additional information.

The impact on Southern Company's effective tax rate, if recognized, is as follows:

	2010	2009	2008
		(in millions)	
Tax positions impacting the effective tax rate	**$217**	$199	$143
Tax positions not impacting the effective tax rate	**79**	-	3
Balance of unrecognized tax benefits	**$296**	$199	$146

The tax positions impacting the effective tax rate primarily relate to Georgia state tax credit litigation at Georgia Power and the production activities deduction tax position. However, as discussed in Note 3 under "Income Tax Matters," if Georgia Power is successful in its claim against the Georgia DOR, a significant portion of the tax benefit is expected to be deferred and returned to retail customers and therefore no material impact to net income is expected. 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 – Georgia State Income Tax Credits" and "Tax Method of Accounting for Repairs" for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2010	2009	2008
		(in millions)	
Interest accrued at beginning of year	**$21**	$15	$31
Interest reclassified due to settlements	**-**	-	(49)
Interest accrued during the year	**8**	6	33
Balance at end of year	**$29**	$21	$15

Southern Company classifies interest on tax uncertainties as interest expense. The net amount of interest accrued during 2010 was primarily associated with the Georgia state tax credit litigation.

Southern 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 Southern Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the Georgia state tax credit litigation would substantially reduce the balances. 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

Long-Term Debt Payable to Affiliated Trusts

Certain of the traditional operating companies have formed certain wholly-owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the applicable traditional operating company through the issuance of junior subordinated notes totaling $412 million, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as long-term debt. Each traditional operating company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trust's payment obligations with respect to these securities. At December 31, 2010, preferred securities of $400 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2010	2009
	(in millions)	
Pollution control revenue bonds	**$ 8**	$ -
Capitalized leases	**23**	21
Senior notes	**600**	1,090
Other long-term debt	**670**	2
Total	**$1,301**	$ 1,113

Maturities through 2015 applicable to total long-term debt are as follows: $1.3 billion in 2011; $1.8 billion in 2012; $1.7 billion in 2013; $441 million in 2014; and $1.2 billion in 2015.

Bank Term Loans

Certain of the traditional operating companies have entered into bank term loan agreements. In 2010, Mississippi Power entered into a one-year $125 million aggregate principal amount long-term floating rate bank loan that bears interest based on one-month London Interbank Offered Rate (LIBOR). The proceeds from this loan were used to repay maturing long-term and short-term indebtedness and for other general corporate purposes, including Mississippi Power's continuous construction program. At December 31, 2010 and 2009, certain of the traditional operating companies had outstanding bank term loans totaling $615 million and $490 million, respectively.

Senior Notes

Southern Company and its subsidiaries issued a total of $2.9 billion of senior notes in 2010. Southern Company issued $400 million, and the traditional operating companies' combined issuances totaled $2.5 billion. The proceeds of these issuances were used to repay long-term and short-term indebtedness and for other general corporate purposes including the applicable subsidiary's continuous construction program.

At December 31, 2010 and 2009, Southern Company and its subsidiaries had a total of $15.2 billion and $14.7 billion, respectively, of senior notes outstanding. At December 31, 2010 and 2009, Southern Company had a total of $1.6 billion and $1.8 billion, respectively, of senior notes outstanding.

Subsequent to December 31, 2010, Georgia Power issued $300 million aggregate principal amount of Series 2011A Floating Rate Senior Notes due January 15, 2013. The proceeds were used to repay a portion of Georgia Power's outstanding short-term indebtedness and for general corporate purposes, including Georgia Power's continuous construction program.

Pollution Control and Other Revenue Bonds

Pollution control obligations represent loans to the traditional operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The traditional operating companies have $3.1 billion of outstanding pollution control revenue bonds and are 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.

In December 2010, Mississippi Power incurred obligations relating to the issuance of $100 million of revenue bonds in two series, each of which is due December 1, 2040. The first series of $50 million was issued with an initial fixed rate of 2.25% through January 14, 2013 and the second series of $50 million was issued with a floating rate. Proceeds from the second series bonds were classified as restricted cash at December 31, 2010 and these bonds were redeemed on February 8, 2011. The proceeds from the first series bonds were used to finance the acquisition and construction of buildings and immovable equipment in connection with Mississippi Power's construction of the Kemper IGCC.

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. Alabama Power and Gulf Power have granted one or more liens on certain of their respective property in connection with the issuance of certain pollution control revenue bonds with an outstanding principal amount of $194 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 other subsidiaries.

Bank Credit Arrangements

The following table outlines the credit arrangements by company:

			Executable Term-Loans		Expires			Expires Within One Year[(a)]	
Company	**Total**	**Unused**	**One Year**	**Two Years**	**2011**	**2012**	**2013**	**Term Loan Option**	**No Term Loan Option**
		(in millions)				*(in millions)*		*(in millions)*	
Southern Company	$ 950	$ 950	$ -	$ -	$ -	$950	$ -	$ -	$ -
Alabama Power	1,271	1,271	372	-	506	765	-	372	134
Georgia Power	1,715	1,703	220	40	595	1,120	-	260	335
Gulf Power	240	240	210	-	240	-	-	210	30
Mississippi Power	161	161	65	41	161	-	-	106	55
Southern Power	400	400	-	-	-	400	-	-	-
Other	60	60	60	-	60	-	-	60	-
Total	$4,797	$4,785	$927	$81	$1,562	$ 3,235	$ -	$1,008	$554

(a) Reflects facilities expiring on or before December 31, 2011.

All of the credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average approximately ½ of 1% or less for Southern Company, the traditional operating companies, and Southern Power. Compensating balances are not legally restricted from withdrawal.

Most of the credit arrangements with banks have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements, other hybrid securities. At December 31, 2010, Southern Company, Southern Power, and the traditional operating companies were each in compliance with their respective debt limit covenants.

In addition, the credit arrangements typically contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness above a specified threshold. The cross default provisions are restricted only to the indebtedness, including any guarantee obligations, of the company that has such credit arrangements. Southern Company and its subsidiaries are currently in compliance with all such covenants.

A portion of the $4.8 billion unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support as of December 31, 2010 was approximately $1.3 billion. Subsequent to December 31, 2010, Georgia Power's remarketing of $137 million of puttable variable rate pollution control bonds increased the total requiring liquidity support to $522 million.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of committed bank credit arrangements. Southern Company and the traditional operating companies may also borrow through various other arrangements with banks. The amount of short-term bank loans included in notes payable in the balance sheets at December 31, 2010 was $1 million. There were no short term-bank loans included in notes payable in the balance sheets at December 31, 2009. At December 31, 2010, the Southern Company system had approximately $1.3 billion of commercial paper borrowings outstanding with a weighted average interest rate of 0.3% per annum. During 2010, Southern Company had an average of $690 million of commercial paper outstanding at a weighted average interest rate of 0.3% per annum and the maximum amount outstanding was $1.3 billion. At December 31, 2009, the Southern Company system had approximately $638 million of commercial paper borrowings outstanding with a weighted average interest rate of 0.3% per annum. During 2009, Southern Company had an average of $956 million of commercial paper outstanding at a weighted average interest rate of 0.4% per annum and the maximum amount outstanding was $1.4 billion.

Changes in Redeemable Preferred Stock of Subsidiaries

Each of the traditional operating companies has issued preferred and/or preference stock. The preferred stock of Alabama Power and Mississippi Power contains a feature that allows the holders to elect a majority of such subsidiary's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of Alabama Power and Mississippi Power, this preferred stock is presented as "Redeemable Preferred Stock of Subsidiaries" in a manner consistent with temporary equity under applicable accounting standards. The preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power do not contain such a provision that would allow the holders to elect a majority of such subsidiary's board. As a result, under applicable accounting standards, the preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power are required to be shown as "noncontrolling interest," separately presented as a component of "Stockholders' Equity" on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

The following table presents changes during the year in redeemable preferred stock of subsidiaries for Southern Company:

	Redeemable Preferred Stock of Subsidiaries
	(in millions)
Balance at December 31, 2007	$498
Issued	-
Redeemed	(125)
Other	2
Balance at December 31, 2008	$375
Issued	-
Redeemed	-
Balance at December 31, 2009	$375
Issued	-
Redeemed	-
Balance at December 31, 2010	**$375**

7. COMMITMENTS

Construction Program

The construction programs of the Company's subsidiaries are currently estimated to include a base level investment of $4.9 billion in 2011, $5.1 billion in 2012, and $4.5 billion in 2013. These amounts include $335 million, $207 million, and $220 million in 2011, 2012, and 2013, respectively, for construction expenditures related to contractual purchase commitments for nuclear fuel included herein under "Fuel and Purchased Power Commitments." Included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $341 million, $427 million, and $452 million for 2011, 2012, and 2013, respectively. The capital budget amounts for 2011-2013 include amounts for the construction of Plant Vogtle Units 3 and 4. Of the estimated total $4.4 billion in capital costs for Plant Vogtle Units 3 and 4, approximately $943 million is expected to be incurred from 2014 through 2017. The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirement and replacement decisions, to meet new regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2010, significant purchase commitments were outstanding in connection with the ongoing construction program, which includes new facilities and capital improvements to transmission, distribution, and generation facilities, including those to meet environmental standards. See Note 3 under "Retail Regulatory Matters – Georgia Power – Nuclear Construction," "Retail Regulatory Matters – Georgia Power – Other Construction," and "Retail Regulatory Matters – Mississippi Power Integrated Coal Gasification Combined Cycle" for additional information.

Long-Term Service Agreements

The traditional operating companies and Southern Power have entered into long-term service agreements (LTSAs) with General Electric (GE), Alstom Power, Inc., Mitsubishi Power Systems Americas, Inc., and Siemens AG for the purpose of securing maintenance support for the combined cycle and combustion turbine generating facilities owned or under construction by the subsidiaries. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs are also obligated to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments under the LTSAs, which are subject to price escalation, are made at various intervals based on actual operating hours or number of gas turbine starts of the respective units. Total remaining payments under these agreements for facilities owned are currently estimated at $2.1 billion over the remaining life of the agreements, which are currently estimated to range up to 23 years. However, the LTSAs contain various cancellation provisions at the option of the purchasers.

Georgia Power has also entered into a LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $6 million. The contract contains cancellation provisions at the option of Georgia Power.

Payments made under the LTSAs prior to the performance of any work are recorded as a prepayment in the balance sheets. All work performed is capitalized or charged to expense (net of any joint owner billings), as appropriate based on the nature of the work.

Limestone Commitments

As part of Southern Company's program to reduce sulfur dioxide emissions from its coal plants, the traditional operating companies have 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. Southern Company has a minimum contractual obligation of 6.9 million tons, equating to approximately $282 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are $39 million in 2011, $40 million in 2012, $42 million in 2013, $43 million in 2014, and $29 million in 2015.

Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements of the generating plants, Southern Company has entered into various long-term commitments for the procurement of fossil, biomass fuel, and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emissions allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2010. Also, Southern Company has entered into various long-term commitments for the purchase of capacity and electricity.

Total estimated minimum long-term obligations at December 31, 2010 were as follows:

	Commitments				
	Natural Gas	Coal	Nuclear Fuel	Biomass Fuel	Purchased Power*
	(in millions)				
2011	$1,357	$ 3,810	$ 335	$ -	$ 260
2012	1,226	1,882	207	14	269
2013	1,054	1,362	220	18	237
2014	908	873	208	18	268
2015	779	783	141	18	291
2016 and thereafter	3,413	1,798	807	110	2,439
Total	$8,737	$10,508	$1,918	$178	$3,764

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

Additional commitments for fuel will be required to supply Southern Company's future needs. Total charges for nuclear fuel included in fuel expense amounted to $184 million in 2010, $160 million in 2009, and $147 million in 2008.

Coal commitments for Mississippi Power include a minimum annual management fee of $38 million beginning in 2014 from the executed 40-year management contract with Liberty Fuels, LLC related to the Kemper IGCC.

Operating Leases

In 2001, Mississippi Power began the initial 10-year term of a lease agreement for a combined cycle generating facility built at Plant Daniel for approximately $370 million. In 2003, the generating facility was acquired by Juniper Capital L.P. (Juniper), a limited partnership whose investors are unaffiliated with Mississippi Power. Simultaneously, Juniper entered into a restructured lease agreement with Mississippi Power. Juniper has also entered into leases with other parties unrelated to Mississippi Power. The assets leased by Mississippi Power comprise less than 50% of Juniper's assets. Mississippi Power is not required to consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. The lease agreement is treated as an operating lease for accounting purposes as well as for both retail and wholesale rate recovery purposes. The initial lease term ends in 2011, and the lease includes a purchase and renewal option based on the cost of the facility at the inception of the lease. Mississippi Power is required to amortize approximately 4% of the initial acquisition cost over the initial lease term. In April 2010, Mississippi Power was required to notify the lessor, Juniper, if it intended to terminate the lease at the end of the initial term expiring in October 2011. Mississippi Power chose not to give notice to terminate the lease. Mississippi Power has the option to purchase the Plant Daniel combined cycle generating units for approximately $354 million or renew the lease for approximately $31 million annually for 10 years. Mississippi Power will have to provide notice of its intent to either renew the lease or purchase the facility by July 2011. If the lease is renewed, the agreement calls for Mississippi Power to amortize an additional 17% of the initial completion cost over the renewal period. Upon termination of the lease, at Mississippi Power's option, it may either exercise its purchase option or the facility can be sold to a third party. If Mississippi Power does not exercise either its purchase option or its renewal option, Mississippi Power could lose its rights to some or all of the 1,064 MWs of capacity at that time. The ultimate outcome of this matter cannot be determined at this time.

The lease provides for a residual value guarantee, approximately 73% of the acquisition cost, by Mississippi Power that is due upon termination of the lease in the event that Mississippi Power does not renew the lease or purchase the assets and that the fair market value is less than the unamortized cost of the asset. A liability of approximately $2 million, $3 million, and $5 million for the fair market value of this residual value guarantee is included in the balance sheets as of December 31, 2010, 2009, and 2008, respectively.

Southern Company also has other operating lease agreements with various terms and expiration dates. Total operating lease expenses were $188 million, $186 million, and $184 million for 2010, 2009, and 2008, respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

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

	Minimum Lease Payments			
	Plant Daniel	Barges & Rail Cars	Other	Total
		(in millions)		
2011	$28	$ 74	$ 52	$154
2012	-	58	35	93
2013	-	48	29	77
2014	-	39	24	63
2015	-	14	17	31
2016 and thereafter	-	16	87	103
Total	$28	$249	$244	$521

For the traditional operating companies, a majority of the barge and rail car lease expenses are recoverable through fuel cost recovery provisions. In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases expire in 2011, 2012, 2013, 2014, 2015, and 2016 and the maximum obligations under these leases are $40 million, $1 million, $39 million, $8 million, $5 million, and $4 million, respectively. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

Guarantees

As discussed earlier in this Note under "Operating Leases," Alabama Power, Georgia Power, and Mississippi Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

During 2010, Southern Company issued 19.6 million shares of common stock for $629 million through the Southern Investment Plan and employee and director stock plans. In addition, Southern Company issued 4.1 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity offering program and received cash proceeds of $143 million, net of $1 million in fees and commissions. In 2009, Southern Company raised $673 million from the issuance of 22.6 million new common shares through the Southern Investment Plan and employee and director stock plans. In 2009, Southern Company issued 19.9 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity offering program and received cash proceeds of $613 million, net of $6 million in fees and commissions.

Shares Reserved

At December 31, 2010, a total of 66 million shares were reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (which includes stock options and performance shares units as discussed below). Of the total 66 million shares reserved, there were 10 million shares of common stock remaining available for awards under the stock option and performance share plans as of December 31, 2010.

Stock Option Plan

Southern Company provides non-qualified stock options to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2010, there were 7,330 current and former employees participating in the stock option plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. Southern 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

Southern 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	48,247,319	$32.10
Granted	9,582,288	31.22
Exercised	(7,024,176)	28.15
Cancelled	(93,845)	31.02
Outstanding at December 31, 2010	**50,711,586**	**$32.48**
Exercisable at December 31, 2010	**34,564,434**	**$32.81**

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 $292 million and $188 million, respectively.

As of December 31, 2010, there was $5 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 10 months.

For the years ended December 31, 2010, 2009, and 2008, total compensation cost for stock option awards recognized in income was $22 million, $23 million, and $20 million, respectively, with the related tax benefit also recognized in income of $9 million, $9 million, and $8 million, respectively.

The total intrinsic value of options exercised during the years ended December 31, 2010, 2009, and 2008 was $57 million, $9 million, and $45 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $22 million, $4 million, and $17 million for the years ended December 31, 2010, 2009, and 2008, respectively.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2010, 2009, and 2008 was $198 million, $19 million, and $113 million, 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 Southern Company system 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, 1,050,052 performance share units were granted with a weighted-average grant date fair value of $30.13. During 2010, 141,711 performance share units were forfeited resulting in 908,341 unvested units outstanding at December 31, 2010.

For the year ended December 31, 2010, total compensation cost for performance share units recognized in income was $9 million, with the related tax benefit also recognized in income of $4 million. As of December 31, 2010, there was $18 million of total unrecognized compensation cost related to performance share award units that will be recognized over the next two years.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. The effect of both stock options and performance share award units were determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Average Common Stock Shares		
	2010	2009	2008
		(in thousands)	
As reported shares	**832,189**	794,795	771,039
Effect of options	**4,792**	1,620	3,809
Diluted shares	**836,981**	796,415	774,848

Stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive were 13.1 million and 37.7 million at December 31, 2010 and 2009, respectively. Assuming an average stock price of $38.01 (the highest exercise price of the anti-dilutive options outstanding), the effect of options would have increased by 0.8 million and 3.4 million shares for the years ended December 31, 2010 and 2009, respectively.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2010, consolidated retained earnings included $5.9 billion of undistributed retained earnings of the subsidiaries. Southern Power's credit facility contains potential limitations on the payment of common stock dividends; as of December 31, 2010, Southern Power was in compliance with all such requirements.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests, is $235 million and $237 million, respectively, per incident, but not more than an aggregate of $35 million per company to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, both companies have policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

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

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

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $42 million and $70 million, respectively.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes. In the event of a loss, the amount of insurance available may not be adequate to cover property damage and other incurred expenses.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

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

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 10	$ -	$ 10
Interest rate derivatives	-	10	-	10
Foreign currency derivatives	-	3	-	3
Nuclear decommissioning trusts:[a]				
Domestic equity	604	60	-	664
U.S. Treasury and government agency securities	20	220	-	240
Municipal bonds	-	53	-	53
Corporate bonds	-	220	-	220
Mortgage and asset backed securities	-	119	-	119
Other	-	74	-	74
Cash equivalents and restricted cash	351	-	-	351
Other	9	51	19	79
Total	$984	$820	$ 19	$1,823
Liabilities:				
Energy-related derivatives	$-	$206	$-	$206
Interest rate derivatives	-	1	-	1
Total	$-	$207	$-	$207

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

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas 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 LIBOR interest rates. Interest rate and foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. Inputs for foreign currency derivatives are from observable market sources. See Note 11 for additional information on how these derivatives are used.

"Other investments" include investments in funds that are valued using the market approach and income approach. Securities that are traded in the open market are valued at the closing price on their principal exchange as of the measurement date. Discounts are applied in accordance with GAAP when certain trading restrictions exist. For investments that are not traded in the open market, the price paid will have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan execution. As the investments mature or if market conditions change materially, further analysis of the fair market value of the investment is performed. This analysis is typically based on a metric, such as multiple of earnings, revenues, earnings before interest and income taxes, or earnings adjusted for certain cash changes. These multiples are based on comparable multiples for publicly traded companies or other relevant prior transactions.

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

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

As of December 31, 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 millions)			
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$ 65	None	Daily	1 to 3 days
Other – commingled funds	67	None	Daily	Not applicable
Trust-owned life insurance	86	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	351	None	Daily	Not applicable
Other:				
Money market funds	2	None	Daily	Not applicable

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

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

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the Securities and Exchange Commission 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.

Changes in the fair value measurement of the Level 3 items using significant unobservable inputs for the year ended December 31, 2010 were as follows:

	Level 3 Other
	(in millions)
Beginning balance at December 31, 2009	$35
Total gains (losses) - realized/unrealized:	
Included in earnings	(1)
Included in OCI	5
Transfers out of Level 3	(20)
Ending balance at December 31, 2010	**$19**

Transfers in and out of the levels of fair value hierarchy are recognized as of the end of the reporting period. The value of one of the investments was reclassified from Level 3 to Level 1 because the securities began trading on the public market. The reclassification is reflected in the table above as a transfer out of Level 3 at its fair value.

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 millions)	
Long-term debt:		
2010	**$19,356**	**$20,073**
2009	$19,145	$19,567

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

11. DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each 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 traditional operating companies and Southern Power enter 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 traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel-hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts. Certain of the traditional operating companies have recently started using significantly more financial options per the guidelines of their respective PSCs, which is expected to continue to mitigate price volatility. Southern Power has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

To mitigate residual risks relative to movements in electricity prices, the electric utilities may enter into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the electric utilities may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

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

- *Regulatory Hedges* **–** Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' 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 respective fuel cost recovery clauses.
- *Cash Flow Hedges* **–** Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* **–** Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2010, the net volume of energy-related derivative contracts for power and natural gas positions for the Southern Company system, 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:

Power			**Gas**		
Net Sold Megawatt-hours	**Longest Hedge Date**	**Longest Non-Hedge Date**	**Net Purchased mmBtu***	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in millions)			*(in millions)*		
1	2011	2011	149	2015	2015

* million British thermal units

In addition to the volumes discussed in the tables above, the traditional operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 4 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2011 are immaterial for Southern Company.

Interest Rate Derivatives

Southern Company and certain subsidiaries also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. 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 with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset with any difference representing ineffectiveness.

At December 31, 2010, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2010
	(in millions)				*(in millions)*
Cash flow hedges of existing debt					
	$300	3-month LIBOR + 0.40% spread	1.24%*	October 2011	$(1)
Fair value hedges of existing debt					
	350	4.15%	3-month LIBOR + 1.96%* spread	May 2014	10
Total	$650				$ 9

* Weighted Average

For the year ended December 31, 2010, the Company had realized net gains of $2 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these gains has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings.

Subsequent to December 31, 2010, Alabama Power entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $200 million.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2011 is $17 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

Foreign Currency Derivatives

Southern Company and certain subsidiaries may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge 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. Any ineffectiveness is recorded directly to earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2010, the following foreign currency derivatives were outstanding:

	Notional Amount	Forward Rate	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2010
	(in millions)			*(in millions)*
Cash flow hedges of forecasted transactions				
	YEN82	85.326 Yen per Dollar*	Various through May 2011	$ -
Fair value hedges of firm commitments				
	EUR41.1	1.256 Dollars per Euro*	Various through July 2012	3
Total				$3

* Weighted Average

Derivative Financial Statement Presentation and Amounts

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

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2010**	2009	**Balance Sheet Location**	**2010**	2009
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$4**	$1	Liabilities from risk management activities	**$145**	$111
	Other deferred charges and assets	**3**	1	Other deferred credits and liabilities	**55**	66
Total derivatives designated as hedging instruments for regulatory purposes		**$7**	$2		**$200**	$177
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	**$-**	$3	Liabilities from risk management activities	**$1**	$ 5
Interest rate derivatives:	Other current assets	**6**	3	Liabilities from risk management activities	**1**	6
	Other deferred charges and assets	**4**	-	Other deferred credits and liabilities	**-**	-
Foreign currency derivatives:	Other current assets	**2**	-	Liabilities from risk management activities	**-**	-
	Other deferred charges and assets	**1**	-	Other deferred credits and liabilities	**-**	-
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$13**	$6		**$2**	$11
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$2**	$ 2	Liabilities from risk management activities	**$5**	$ 3
	Other deferred charges and assets	**1**	-	Other deferred credits and liabilities	**-**	-
Total derivatives not designated as hedging instruments		**$3**	$2		**$5**	$3
Total		**$23**	$10		**$207**	$191

All derivative instruments are measured at fair value. See Note 10 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 millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$(145)**	$(111)	Other regulatory liabilities, current	**$4**	$1
	Other regulatory assets, deferred	**(55)**	(66)	Other regulatory liabilities, deferred	**3**	1
Total energy-related derivative gains (losses)		**$(200)**	$(177)		**$7**	$2

For the twelve months ended December 31, 2010, the pre-tax gains from interest rate derivatives designated as fair value hedging instruments on Southern Company's statement of income were $10 million. This amount was offset with changes in the fair value of the hedged debt.

For the twelve months ended December 31, 2010, the pre-tax gains from foreign currency derivatives designated as fair value hedging instruments on Southern Company's statement of income were $3 million. These amounts were offset with changes in the fair value of the purchase commitment related to equipment purchases.

For the years ended December 31, 2010, 2009, and 2008, the pre-tax effect of 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 millions)				*(in millions)*	
Energy-related derivatives	**$ 1**	$(2)	$(1)	Fuel	**$ -**	$ -	$ -
Interest rate derivatives	**(3)**	(5)	(47)	Interest expense, net of amounts capitalized	**(25)**	(46)	(19)
Foreign currency derivatives	**1**	-	-	Other operations and maintenance	**1**	-	-
Total	**$(1)**	$(7)	$(48)		**$ (24)**	$(46)	$(19)

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 as follows:

Derivatives not Designated as Hedging Instruments	**Unrealized Gain (Loss) Recognized in Income**			
		Amount		
Derivative Category	**Statements of Income Location**	**2010**	2009	2008
			(in millions)	
Energy-related derivatives:	Wholesale revenues	**$(2)**	$ 5	$ (2)
	Fuel	**1**	(6)	5
	Purchased power	**(1)**	(4)	(2)
Total		**$(2)**	$(5)	$ 1

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 Southern Company subsidiaries. At December 31, 2010, the fair value of derivative liabilities with contingent features was $40 million.

At December 31, 2010, the Company had no collateral posted with its derivative counterparties. The maximum potential collateral requirement arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, is $40 million. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. 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.

12. SEGMENT AND RELATED INFORMATION

Southern Company's reportable business segments are the sale of electricity in the Southeast by the four traditional operating companies and Southern Power. Southern Power's revenues from sales to the traditional operating companies were $371 million, $544 million, and $638 million in 2010, 2009, and 2008, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications, renewable energy projects, and leveraged lease projects. All other intersegment revenues are not material. Financial data for business segments and products and services was as follows:

	Electric Utilities						
	Traditional Operating Companies	**Southern Power**	**Eliminations**	**Total**	**All Other**	**Eliminations**	**Consolidated**
				(in millions)			
2010							
Operating revenues	**$16,713**	**$1,129**	**$(468)**	**$17,374**	**$162**	**$(80)**	**$17,456**
Depreciation and amortization	**1,375**	**119**	**-**	**1,494**	**19**	**-**	**1,513**
Interest income	**22**	**-**	**-**	**22**	**3**	**(1)**	**24**
Interest expense	**757**	**76**	**-**	**833**	**62**	**-**	**895**
Income taxes	**1,039**	**77**	**-**	**1,116**	**(90)**	**-**	**1,026**
Segment net income (loss)*	**1,859**	**130**	**-**	**1,989**	**(10)**	**(4)**	**1,975**
Total assets	**51,145**	**3,276**	**(128)**	**54,293**	**1,279**	**(540)**	**55,032**
Gross property additions	**4,029**	**300**	**-**	**4,329**	**114**	**-**	**4,443**
2009							
Operating revenues	$15,304	$ 947	$(609)	$15,642	$ 165	$(64)	$15,743
Depreciation and amortization	1,378	98	-	1,476	27	-	1,503
Interest income	21	-	-	21	3	(1)	23
Interest expense	749	85	-	834	71	-	905
Income taxes	902	86	-	988	(92)	-	896
Segment net income (loss)*	1,679	156	-	1,835	(193)	1	1,643
Total assets	48,403	3,043	(143)	51,303	1,223	(480)	52,046
Gross property additions	4,568	331	-	4,899	14	-	4,913
2008							
Operating revenues	$16,521	$ 1,314	$(835)	$17,000	$ 182	$ (55)	$17,127
Depreciation and amortization	1,325	89	-	1,414	29	-	1,443
Interest income	32	1	-	33	-	-	33
Interest expense	689	83	-	772	94	-	866
Income taxes	944	93	-	1,037	(122)	-	915
Segment net income (loss)*	1,703	144	-	1,847	(104)	(1)	1,742
Total assets	44,794	2,813	(139)	47,468	1,407	(528)	48,347
Gross property additions	4,058	50	-	4,108	14	-	4,122

*After dividends on preferred and preference stock of subsidiaries

Products and Services

	Electric Utilities' Revenues			
Year	**Retail**	**Wholesale**	**Other**	**Total**
		(in millions)		
2010	**$14,791**	**$1,994**	**$589**	**$17,374**
2009	13,307	1,802	533	15,642
2008	14,055	2,400	545	17,000

13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial data for 2010 and 2009 are as follows:

				Per Common Share			
						Trading Price Range	
Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	Basic Earnings	Dividends	High	Low
	(in millions)						
March 2010	**$4,157**	**$ 922**	**$495**	**$0.60**	**$0.4375**	**$33.73**	**$30.85**
June 2010	**4,208**	**951**	**510**	**0.62**	**0.4550**	**35.45**	**32.04**
September 2010	**5,320**	**1,459**	**817**	**0.98**	**0.4550**	**37.73**	**33.00**
December 2010	**3,771**	**470**	**153**	**0.18**	**0.4550**	**38.62**	**37.10**
March 2009	$3,666	$ 490	$126*	$0.16*	$0.4200	$37.62	$26.48
June 2009	3,885	886	478	0.61	0.4375	32.05	27.19
September 2009	4,682	1,415	790	0.99	0.4375	32.67	30.27
December 2009	3,510	477	249	0.31	0.4375	34.47	30.89

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

* Southern Company's MC Asset Recovery litigation settlement reduced earnings by $202 million, or 25 cents per share, during the first quarter 2009.

[This page intentionally left blank]

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA

For the Periods Ended December 2006 through 2010

Southern Company and Subsidiary Companies 2010 Annual Report

	2010	2009	2008	2007	2006
Operating Revenues (in millions)	**$17,456**	$15,743	$17,127	$15,353	$14,356
Total Assets (in millions)	**$55,032**	$52,046	$48,347	$45,789	$42,858
Gross Property Additions (in millions)	**$4,443**	$4,913	$4,122	$3,658	$3,072
Return on Average Common Equity (percent)	**12.71**	11.67	13.57	14.60	14.26
Cash Dividends Paid Per Share of Common Stock	**$1.8025**	$1.7325	$1.6625	$1.595	$1.535
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries (in millions)	**$1,975**	$1,643	$1,742	$1,734	$1,573
Earnings Per Share --					
Basic	**$2.37**	$2.07	$2.26	$2.29	$2.12
Diluted	**2.36**	2.06	2.25	2.28	2.10
Capitalization (in millions):					
Common stock equity	**$ 16,202**	$ 14,878	$13,276	$ 12,385	$ 11,371
Preferred and preference stock of subsidiaries	**707**	707	707	707	246
Redeemable preferred stock of subsidiaries	**375**	375	375	373	498
Long-term debt	**18,154**	18,131	16,816	14,143	12,503
Total (excluding amounts due within one year)	**$35,438**	$34,091	$31,174	$27,608	$24,618
Capitalization Ratios (percent):					
Common stock equity	**45.7**	43.6	42.6	44.9	46.2
Preferred and preference stock of subsidiaries	**2.0**	2.1	2.3	2.6	1.0
Redeemable preferred stock of subsidiaries	**1.1**	1.1	1.2	1.3	2.0
Long-term debt	**51.2**	53.2	53.9	51.2	50.8
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	**$19.21**	$18.15	$17.08	$16.23	$15.24
Market price per share:					
High	**$38.62**	$37.62	$40.60	$39.35	$37.40
Low	**30.85**	26.48	29.82	33.16	30.48
Close (year-end)	**38.23**	33.32	37.00	38.75	36.86
Market-to-book ratio (year-end) (percent)	**199.0**	183.6	216.6	238.8	241.9
Price-earnings ratio (year-end) (times)	**16.1**	16.1	16.4	16.9	17.4
Dividends paid (in millions)	**$1,496**	$1,369	$1,279	$1,204	$1,140
Dividend yield (year-end) (percent)	**4.7**	5.2	4.5	4.1	4.2
Dividend payout ratio (percent)	**75.7**	83.3	73.5	69.5	72.4
Shares outstanding (in thousands):					
Average	**832,189**	794,795	771,039	756,350	743,146
Year-end	**843,340**	819,647	777,192	763,104	746,270
Stockholders of record (year-end)	**160,426***	92,799	97,324	102,903	110,259
Traditional Operating Company Customers (year-end) (in thousands):					
Residential	**3,813**	3,798	3,785	3,756	3,706
Commercial	**580**	580	594	600	596
Industrial	**15**	15	15	15	15
Other	**9**	9	8	6	5
Total	**4,417**	4,402	4,402	4,377	4,322
Employees (year-end)	**25,940**	26,112	27,276	26,472	26,091

* In July 2010, Southern Company changed its transfer agent from Southern Company Services, Inc. to Mellon Investor Services LLC. The change in the number of stockholders of record is primarily attributed to the calculation methodology used by Mellon Investor Services LLC.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2006 through 2010
Southern Company and Subsidiary Companies 2010 Annual Report

	2010	2009	2008	2007	2006
Operating Revenues (in millions):					
Residential	**$ 6,319**	$ 5,481	$ 5,476	$5,045	$4,716
Commercial	**5,252**	4,901	5,018	4,467	4,117
Industrial	**3,097**	2,806	3,445	3,020	2,866
Other	**123**	119	116	107	102
Total retail	**14,791**	13,307	14,055	12,639	11,801
Wholesale	**1,994**	1,802	2,400	1,988	1,822
Total revenues from sales of electricity	**16,785**	15,109	16,455	14,627	13,623
Other revenues	**671**	634	672	726	733
Total	**$17,456**	$15,743	$17,127	$15,353	$14,356
Kilowatt-Hour Sales (in millions):					
Residential	**57,798**	51,690	52,262	53,326	52,383
Commercial	**55,492**	53,526	54,427	54,665	52,987
Industrial	**49,984**	46,422	52,636	54,662	55,044
Other	**943**	953	934	962	920
Total retail	**164,217**	152,591	160,259	163,615	161,334
Wholesale sales	**32,570**	33,503	39,368	40,745	38,460
Total	**196,787**	186,094	199,627	204,360	199,794
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**10.93**	10.60	10.48	9.46	9.00
Commercial	**9.46**	9.16	9.22	8.17	7.77
Industrial	**6.20**	6.04	6.54	5.52	5.21
Total retail	**9.01**	8.72	8.77	7.72	7.31
Wholesale	**6.12**	5.38	6.10	4.88	4.74
Total sales	**8.53**	8.12	8.24	7.16	6.82
Average Annual Kilowatt-Hour Use Per Residential Customer	**15,176**	13,607	13,844	14,263	14,235
Average Annual Revenue Per Residential Customer	**$1,659**	$1,443	$1,451	$1,349	$1,282
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**42,963**	42,932	42,607	41,948	41,785
Maximum Peak-Hour Demand (megawatts):					
Winter	**35,593**	33,519	32,604	31,189	30,958
Summer	**36,321**	34,471	37,166	38,777	35,890
System Reserve Margin (at peak) (percent)	**23.3**	26.4	15.3	11.2	17.1
Annual Load Factor (percent)	**62.2**	60.6	58.7	57.6	60.8
Plant Availability (percent):					
Fossil-steam	**91.4**	91.3	90.5	90.5	89.3
Nuclear	**92.1**	90.1	91.3	90.8	91.5
Source of Energy Supply (percent):					
Coal	**55.0**	54.7	64.0	67.1	67.2
Nuclear	**14.1**	14.9	14.0	13.4	14.0
Hydro	**2.5**	3.9	1.4	0.9	1.9
Oil and gas	**23.7**	22.5	15.4	15.0	12.9
Purchased power	**4.7**	4.0	5.2	3.6	4.0
Total	**100.0**	100.0	100.0	100.0	100.0

ALABAMA POWER COMPANY

FINANCIAL SECTION

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2010.

Charles D. McCrary
President and Chief Executive Officer

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

February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the "Company") (a wholly owned subsidiary of 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. Our audits also included the financial statement schedule of the Company listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 II-133 to II-177) present fairly, in all material respects, the financial position of Alabama 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. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

Birmingham, Alabama
February 25, 2011

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel, capital expenditures, and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to more than 1.4 million customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The fossil/hydro 2010 Peak Season EFOR was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, 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 preferred and preference stock is the primary measure of the Company's financial performance. 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 – fossil/hydro	5.06% or less	1.22%
Net Income After Dividends on Preferred and Preference Stock	$696 million	$707 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2010 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

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

The Company's net income after dividends on preferred and preference stock of $670 million in 2009 increased $54 million (8.8%) over the prior year. The increase was primarily due to the corrective rate package providing for adjustments associated with customer charges to certain existing rate structures effective in January 2009, a decrease in other operations and maintenance expenses, and an increase in AFUDC equity. The increase was partially offset by an overall decline in base rate revenues attributable to a decline in kilowatt-hour (KWH) sales, resulting from a recessionary economy and unfavorable weather conditions.

The Company's net income after dividends on preferred and preference stock of $616 million in 2008 increased $36 million (6.2%) over the prior year. This improvement was primarily due to an increase in retail base rate revenues resulting from an increase in rates under the Rate RSE and the Rate CNP Environmental that took effect January 1, 2008, partially offset by higher non-fuel operating expenses and depreciation.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year		
	2010	**2010**	2009	2008
		(in millions)		
Operating revenues	**$5,976**	**$447**	$(548)	$717
Fuel	**1,851**	**27**	(360)	422
Purchased power	**280**	**(27)**	(231)	100
Other operations and maintenance	**1,418**	**207**	(48)	73
Depreciation and amortization	**606**	**61**	25	48
Taxes other than income taxes	**332**	**10**	15	20
Total operating expenses	**4,487**	**278**	(599)	663
Operating income	**1,489**	**169**	51	54
Total other income and (expense)	**(280)**	**(53)**	19	2
Income taxes	**463**	**79**	16	17
Net income	**746**	**37**	54	39
Dividends on preferred and preference stock	**39**	**-**	-	3
Net income after dividends on preferred and preference stock	**$ 707**	**$ 37**	$ 54	$ 36

Operating Revenues

Operating revenues for 2010 were $6.0 billion, reflecting a $447 million increase from 2009. The following table summarizes the principal factors that have affected operating revenues for the past three years:

	Amount		
	2010	2009	2008
		(in millions)	
Retail – prior year	**$4,497**	$4,862	$4,407
Estimated change in –			
Rates and pricing	**310**	174	246
Sales growth (decline)	**(11)**	(109)	26
Weather	**199**	(12)	(70)
Fuel and other cost recovery	**81**	(418)	253
Retail – current year	**5,076**	4,497	4,862
Wholesale revenues –			
Non-affiliates	**465**	620	712
Affiliates	**236**	237	308
Total wholesale revenues	**701**	857	1,020
Other operating revenues	**199**	175	195
Total operating revenues	**$5,976**	$5,529	$6,077
Percent change	**8.1%**	(9.0)%	13.4%

Retail revenues in 2010 were $5.1 billion. These revenues increased $579 million (12.9%) in 2010, decreased $365 million (7.5%) in 2009, and increased $455 million (10.3%) in 2008. The increase in 2010 was due to increases in rates and pricing under Rate RSE and Rate CNP Environmental that took effect January 2010, colder weather in the first and fourth quarters 2010, and warmer weather in the second and third quarters 2010. The decrease in 2009 was due to decreased fuel revenue and a decline in KWH sales, partially offset by the corrective rate package providing for adjustments associated with customer charges to certain existing rate structures. The increase in 2008 was primarily due to an increase in fuel revenue and a base rate increase of 5.6%. See FUTURE EARNINGS POTENTIAL – "PSC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

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

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

	2010	2009	2008
		(in millions)	
Unit power sales –			
Capacity	**$ 84**	$158	$160
Energy	**95**	207	238
Total	**179**	365	398
Other power sales –			
Capacity and other	**148**	133	134
Energy	**138**	122	180
Total	**286**	255	314
Total non-affiliated	**$465**	$620	$712

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.

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

In 2010, wholesale revenues from sales to non-affiliates decreased $155 million (25.0%), primarily due to a 39.5% decrease in KWH sales. In May 2010, the long-term unit power sales contracts expired and the unit power sales capacity revenues ceased. Beginning in June 2010, such capacity, which was subject to the unit power sales contracts, became available for retail service. The changes in wholesale revenues from sales to non-affiliates in 2009 and 2008 were not material. Short-term opportunity energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Rate Adjustments" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clauses. The change in wholesale revenues from sales to affiliates for 2010 was not material. In 2009, wholesale revenues from sales to affiliates decreased $71 million (23.1%) primarily due to a 37.6% decrease in price, partially offset by a 23.2% increase in KWH sales to affiliates as a result of greater availability of the Company's generating resources because of a decrease in customer demand within the Company's service territory. In 2008, wholesale revenues from sales to affiliates increased $164 million (113.9%) primarily due to a 62.2% increase in KWH sales to affiliates as a result of greater availability of the Company's generating resources because of a decrease in customer demand within the Company's service territory.

Other operating revenues increased $24 million (13.7%) in 2010 due to a $13 million increase in transmission sales and a $12 million increase in revenues from gas-fueled co-generation steam facilities as a result of greater sales volume. Other operating revenues in 2009 decreased $20 million (10.3%) from 2008 primarily due to a $43 million decrease in revenues from gas-fueled co-generation steam facilities as a result of lower gas prices. This decrease was partially offset by an increase of $10 million in customer charges related to late fees. In 2008, other operating revenues increased $13 million (7.1%) from 2007 primarily due to a $12 million increase in revenues from gas-fueled co-generation steam facilities. Since co-generation steam revenues are generally offset by fuel expense, these revenues did not have a significant impact on earnings for any year reported.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 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 billions)						
Residential	**20.4**	**13.0%**	(1.7)%	(2.6)%	**(0.6)%**	(1.0)%	2.2%
Commercial	**14.7**	**3.8**	(2.5)	(1.4)	**(1.1)**	(2.1)	1.0
Industrial	**20.7**	**11.1**	(15.9)	(3.2)	**11.1**	(15.9)	(3.2)
Other	**0.2**	**(0.8)**	8.1	0.2	**(0.8)**	8.1	0.2
Total retail	**56.0**	**9.7**	(7.6)	(2.5)	**3.5%**	(7.2)%	(0.3)%
Wholesale -							
Non-affiliates	**8.6**	**(39.5)**	(5.8)	(3.6)			
Affiliates	**6.1**	**(6.2)**	23.2	62.2			
Total wholesale	**14.7**	**(29.2)**	1.6	7.6			
Total energy sales	**70.7**	**(1.6)%**	(5.1)%	- %			

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

Retail energy sales in 2009 were 7.6% less than in 2008. Energy sales were down in 2009 across major classes of customers. Residential and commercial sales decreased 1.7% and 2.5%, respectively, due primarily to unfavorable weather and decreased customer demand in 2009 as compared to 2008. Industrial sales decreased 15.9% during the year as a result of decreased customer demand in all sectors, most significantly in the chemical and primary metals sectors, due to a recessionary economy.

Retail energy sales in 2008 were 2.5% less than in 2007. Energy sales were down in 2008 across major classes of customers. Residential and commercial sales decreased 2.6% and 1.4%, respectively, due primarily to unfavorable weather in 2008 compared to 2007. Industrial sales decreased 3.2% during the year primarily as a result of decreased customer demand in the chemical and pipeline, and textiles and food sectors, as a result of a slowing economy that worsened during the fourth quarter 2008.

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

Fuel and Purchased Power Expenses

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

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

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

	2010	2009	2008
Total generation *(billions of KWHs)*	**69.2**	68.8	70.0
Total purchased power *(billions of KWHs)*	**5.0**	6.3	9.2
Sources of generation *(percent)* –			
Coal	**61**	58	66
Nuclear	**19**	20	20
Gas	**15**	13	11
Hydro	**5**	9	3
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.02**	3.02	2.94
Nuclear	**0.60**	0.56	0.50
Gas	**4.47**	5.24	8.30
Average cost of fuel, generated *(cents per net KWH)**	**2.76**	2.79	3.00
Average cost of purchased power *(cents per net KWH)*	**6.42**	6.05	7.44

*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. KWHs generated by hydro are excluded from the average cost of fuel, generated.

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

Fuel and purchased power expenses were $2.1 billion in 2009, a decrease of $591 million (21.7%) below the prior year costs. This decrease was the result of a $367 million decrease related to the volume of KWHs generated and purchased and a $225 million decrease in the cost of fuel resulting from lower natural gas prices and an increase in hydro generation.

Fuel and purchased power expenses were $2.7 billion in 2008, an increase of $522 million (23.7%) above the prior year costs. This increase was the result of a $561 million increase in the cost of fuel, offset by a $39 million decrease related to the volume of KWHs generated and purchased.

Purchased power consists of purchases from affiliates in the Southern Company system and non-affiliated companies. Purchased power transactions among the Company, its affiliates, and non-affiliates will vary from period to period depending on demand and the availability and variable production cost of generating resources at each company. In 2010, purchased power from non-affiliates decreased $16 million (18.2%) due to a 22.4% decrease in the amount of energy purchased, partially offset by a 6.7% increase in the average cost per KWH. In 2009, purchased power from non-affiliates decreased $91 million (50.8%) due to a 34.9% decrease in the amount of energy purchased and a 24.6% decrease in the average cost per KWH. In 2009, purchased power from affiliates decreased $140 million (39.0%) due to a 31.4% decrease in the amount of energy purchased. In 2008, the average cost of purchased power from non-affiliates increased $82 million (84.5%) due to a 67.9% increase in the amount of energy purchased.

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. Uranium prices remained relatively constant during the early portion of 2010 but rose steadily during the second half of the year. At year end, uranium prices remained well below the highs set during 2007. Worldwide uranium production levels increased in 2010; however, secondary supplies and inventories were still required to meet worldwide reactor demand.

Other Operations and Maintenance Expenses

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

In 2009, other operations and maintenance expenses decreased $48 million (3.8%) primarily due to a $39 million decrease in transmission and distribution expenses related to a reduction in overhead line clearing and labor which was offset by a $40 million additional NDR accrual, an $18 million decrease in steam production expense related to fewer scheduled outages, a $13 million decrease in administrative and general expense related to reductions in employee medical and other benefit-related expenses and in the injuries and damages reserve, a $6 million decrease in customer accounts expense, and a $5 million decrease in customer service and information expense.

In 2008, other operations and maintenance expenses increased $73 million (6.2%) primarily due to a $27 million increase in steam production expense related to environmental mandates (which were offset by revenues associated with Rate CNP Environmental) and scheduled outage costs, a $23 million increase in nuclear production expense related to operations and scheduled outage costs, and a $20 million increase in transmission and distribution expense related to overhead line clearing costs.

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

Depreciation and Amortization

Depreciation and amortization increased $61 million (11.2%) in 2010, $25 million (4.8%) in 2009, and $48 million (10.2%) in 2008, primarily due to additions to property, plant, and equipment related to environmental mandates (which were offset by revenues associated with Rate CNP Environmental) and transmission and distribution projects. See Note 3 to financial statements under "Retail Regulatory Matters – Rate CNP" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $10 million (3.1%) in 2010, $15 million (4.9%) in 2009, and $20 million (7.0%) in 2008. The increase in 2010 was primarily due to increases in state and municipal public utility license tax bases and an increase in payroll taxes. The increases in 2009 and 2008 were primarily due to increases in state and municipal public utility license tax bases.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $43 million (54.4%) in 2010 from 2009 primarily due to the completion of construction projects related to environmental mandates at steam generating facilities, partially offset by an increase in nuclear production projects. AFUDC equity increased $33 million (71.7%) in 2009 and $11 million (31.4%) in 2008 primarily due to increases in construction work in progress related to environmental mandates at generating facilities, as well as transmission, distribution, and general plant projects compared to the prior years. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $5 million (1.7%) in 2010. The increase in 2010 was not material. Interest expense, net of amounts capitalized increased $20 million (6.9%) in 2009 primarily due to the issuance of long-term debt, partially offset by additional capitalized interest, as a result of increases in construction work in progress. Interest expense, net of amounts capitalized increased $5 million (1.9%) in 2008 which was not material when compared to the prior year.

Income Taxes

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

Income taxes increased $16 million (4.3%) in 2009, primarily due to higher pre-tax income as compared to 2008, prior year tax return actualization, and an increase in expense related to normal tax contingencies, partially offset by the tax benefits associated with an increase in AFUDC equity and an increase in the Internal Revenue Code, Section 199 production activities deduction.

Income taxes increased $17 million (4.8%) in 2008, primarily due to higher pre-tax income as compared to 2007, partially offset by the tax benefit associated with an increase in AFUDC equity and a decrease in expense related to normal tax contingencies.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years. See Note 3 to financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

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

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

Environmental Matters

Compliance costs related to 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 the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to each of the traditional operating companies. After the Company was dismissed from the original action, the EPA filed a separate action in January 2001 against the Company in the U.S. District Court for the Northern District of Alabama. In the lawsuit against the Company, the EPA alleges that NSR violations occurred at five coal-fired generating facilities operated by the Company. The civil action requests 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. The separate action against the Company is ongoing.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between the Company and the EPA, resolving a portion of the Company's 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 the Company 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 the Company, leaving only three claims for summary disposition or trial, including the claim relating to a facility co-owned by Mississippi Power. 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 $3.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $130 million, $526 million, and $617 million for 2010, 2009, and 2008, respectively. The Company expects that capital expenditures to comply with existing statutes and regulations will be $47 million, $26 million, and $53 million for 2011, 2012, and 2013, respectively. These environmental costs that are known and estimable at this time are included in the Company's approved construction program and capital expenditures under the heading "Capital" in the table FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. In addition, the Company currently estimates additional environmental expenditures may be required to comply with anticipated new statutes and regulations. Such additional environmental expenditures are estimated to be in amounts up to $48 million, $108 million, and $354 million for 2011, 2012, and 2013, respectively. 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.

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 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 $2.6 billion 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 for the 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 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 one area within the Company's service area. State implementation plans demonstrating attainment with the annual standard for all areas have been submitted to the EPA. In September 2006, the EPA published a final rule which increased the stringency of the 24-hour average fine particulate matter air quality standard. In October 2009, the EPA designated the Birmingham area as nonattainment for the 24-hour standard. Although the Birmingham area was initially designated as nonattainment for the 24-hour standard, in September 2010, the EPA determined that the area had attained the standard. 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 State of Alabama, 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 State of Alabama has completed its plan 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 Alabama, 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 Alabama, 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 any of the Company's facilities. The State of Alabama has completed its 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 has already installed a number of SO_2 and NO_x emissions controls to ensure continued compliance with applicable air quality requirements.

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.

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. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Coal Combustion Byproducts

The Company currently operates six 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 also sells a portion of its coal combustion byproducts to third parties for beneficial reuse (approximately one-fourth in recent years). Historically, individual states have regulated coal combustion byproducts and the states in Southern Company's service territory, including the State of Alabama, 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. 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 43 million metric tons. The preliminary estimate of carbon dioxide emissions from these units in 2010 is approximately 45 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.

FERC Matters

In July 2005, the Company filed two applications with the FERC for new 50-year licenses for the Company's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expired in July and August 2007. Since the FERC did not act on the Company's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to the Company, under the terms and conditions of the existing license, until action is taken on the new license applications. The FERC issued an annual license for the Coosa developments in August 2007 and issued an annual license for the Warrior developments in September 2007. These annual licenses were automatically renewed in 2010 without further action by the FERC to allow the Company to continue operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses.

In 2006, the Company initiated the process of developing an application to relicense the Martin hydroelectric project located on the Tallapoosa River. The current Martin license will expire in 2013 and the application for a new license is expected to be filed with the FERC in 2011.

In 2010, the Company initiated the process of developing an application to relicense the Holt hydroelectric project located on the Warrior River. The current Holt license will expire on August 31, 2015, and the application for a new license is expected to be filed prior to that time.

On March 31, 2010, the FERC issued a new 30-year license for the Lewis Smith and Bankhead developments on the Warrior River. The new license authorizes the Company to continue operating these facilities in a manner consistent with past operations. On April 30, 2010, a stakeholders group filed a request for rehearing of the FERC order issuing the new license. On May 27, 2010, the FERC granted the rehearing request for the limited purpose of allowing the FERC additional time to consider the substantive issues raised in the request. The ultimate outcome of this matter cannot be determined at this time.

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

PSC Matters

Retail Rate Adjustments

Rate RSE

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

The Rate RSE increase for 2010 was 3.24%, or $152 million annually, and was effective in January 2010. In December 2010, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2011 and earnings were within the specified return range. Consequently, the retail rates will remain unchanged in 2011 under Rate RSE. Under the terms of Rate RSE, the maximum increase for 2012 cannot exceed 5.00%.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated power purchase agreements (PPAs) under a Rate CNP. There was no adjustment to the Rate CNP to recover certificated PPA costs in 2008 or 2009. Effective April 2010, Rate CNP was reduced by approximately $70 million annually, primarily due to the expiration on May 31, 2010, of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. It is estimated that there will be a slight decrease to the current Rate CNP effective April 2011.

Rate CNP also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Retail rates increased approximately 2.4% in January 2008 and 4.3% in January 2010 due to environmental costs. In October 2008, the Company agreed to defer collection of any increase in rates under this portion of Rate CNP, which permits recovery of costs associated with environmental laws and regulations, from 2009 until 2010. The deferral of the retail rate adjustments had an immaterial impact on annual cash flows, and had no significant effect on the Company's revenues or net income. On December 1, 2010, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflects an incremental increase in the revenue requirement associated with such environmental compliance, which would be recoverable in the billing months of January 2011 through December 2011. In order to afford additional rate stability to customers as the economy continues to recover from the recession, the Alabama PSC ordered on January 4, 2011 that the Company leave in effect for 2011 the factors associated with the Company's environmental compliance costs for the year 2010. Any recoverable amounts associated with 2011 will be reflected in the 2012 filing. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP" for further information. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates under Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. The Rate ECR factor as of January 1, 2011 was 2.403 cents per KWH. Effective with billings beginning in April 2011, the Rate ECR factor will be 2.681 cents per KWH.

As of December 31, 2010, the Company had an under recovered fuel balance of approximately $4 million which is included in deferred under recovered regulatory clause revenues in the balance sheets. As of December 31, 2009, the Company had an over recovered fuel balance of approximately $200 million, of which approximately $22 million was included in deferred over recovered regulatory clause revenues in the balance sheets. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any return of the over recovered fuel costs or recovery of under recovered fuel costs. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for further information.

Natural Disaster Reserve

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

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

On August 20, 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

For the year ended December 31, 2010, the Company accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. For the year ended December 31, 2009, the Company accrued an additional $40 million to the NDR, resulting in an accumulated balance of approximately $75 million. These accruals are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

Steam Service

In February 2009, the Alabama PSC granted a Certificate of Abandonment of Steam Service for the downtown area of the City of Birmingham. The order allows the Company to discontinue general steam service by the earlier of three years from May 14, 2008 or when it has no such remaining steam service customers. The Company was also authorized to honor other contractual obligations to provide steam service, which extend until 2013. Impacts related to the abandonment of steam service are recognized in operating income and are not material to the earnings of the Company.

Nuclear Outage Accounting Order

On August 17, 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, the Company accrued nuclear outage operations and maintenance expenses for the two units of Plant Farley during the 18-month cycle for the outages. In accordance with the new order, nuclear outage expenses will be deferred when the charges actually occur and then amortized over the subsequent 18-month period.

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

Legislation

Stimulus Funding

On April 28, 2010, Southern Company signed a Smart Grid Investment Grant agreement with the U.S. Department of Energy (DOE), formally accepting a $165 million grant under the American Recovery and Reinvestment Act of 2009 (ARRA). 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, $65 million under this agreement.

On May 12, 2010, the Company signed an agreement with the DOE formally accepting a $6 million grant under the ARRA. This funding will be used for hydro generation upgrades. The total upgrade project is expected to cost $30 million and the Company plans to spend $24 million on the project.

The ultimate outcome of these matters 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 financial statements of the Company. 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 financial statements of the Company 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 $141 million for the Company. Although the Internal Revenue Service (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 $132 million in increased cash flow. The Company estimates the potential increased cash flow for 2011 to be between approximately $150 million and $200 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. 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

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded non-cash pre-tax pension income of approximately $19 million, $24 million, and $26 million in 2010, 2009, and 2008, respectively. Postretirement benefit costs for the Company were $14 million, $19 million, and $23 million in 2010, 2009, and 2008, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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 Alabama PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that 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 Alabama Department of Revenue interpretations of existing regulations.
- Identification of 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, the Alabama Department of Revenue, the FERC, or the EPA.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. Recorded revenue includes both billed and unbilled KWH sales. Billings to individual customers are based on the reading of their meters, which is performed on a systematic basis throughout the month.

The Company's unbilled KWH sales include a measured component and an estimated component. Automated meters measure unbilled energy delivered through month-end. Readings from these meters are used to determine the measured unbilled KWH sales and associated revenues.

At month-end for customers where automated meter readings are not available, amounts of unbilled electricity delivered are estimated. Components of the estimate 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, estimated unbilled revenues could be significantly affected. However, as of December 31, 2010, the measured unbilled KWH sales are greater than the estimated unbilled KWH sales.

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 $6 million or less change in total benefit expense and a $73 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 and the nuclear decommissioning trust funds remained stable in value as of December 31, 2010. In December 2010, the Company contributed $38 million to the qualified pension plan. The Company's funding obligations for the nuclear decommissioning trust fund are based on the site study, and the next study is expected to be conducted in 2013.

Net cash provided from operating activities in 2010 totaled $1.4 billion, a decrease of $231 million as compared to 2009. The decrease in cash provided from operating activities was primarily due to receivables and other current liabilities related to less cash collections of regulatory clause revenues when compared to the prior year. This is partially offset by an increase in deferred income taxes related to bonus depreciation. Net cash provided from operating activities in 2009 totaled $1.6 billion, an increase of $424 million as compared to 2008. The increase was primarily due to an increase in net income, a decrease in receivables, and an increase in other current liabilities attributable to collections on regulatory clauses. Net cash provided from operating activities in 2008 totaled $1.2 billion, an increase of $30 million as compared to 2007. The increase included additional use of funds for fossil fuel inventory and payment of operating expenses along with a higher receivables balance as compared to 2007. This use of funds was offset by an increase in cash from net income and higher depreciation along with a decrease in the payments for federal taxes as compared to 2007.

Net cash used for investing activities totaled \$1.0 billion, \$1.2 billion, and \$1.6 billion for 2010, 2009, and 2008, respectively, primarily due to gross property additions to utility plant of \$0.9 billion, \$1.2 billion, and \$1.5 billion for 2010, 2009, and 2008, respectively. These additions were primarily related to environmental mandates, construction of transmission and distribution facilities, replacement of steam generation equipment, and purchases of nuclear fuel.

Net cash used for financing activities totaled \$600 million in 2010 primarily due to payment of common stock dividends. In 2009, net cash used for financing activities totaled \$35 million primarily due to redemptions of debt securities and dividends paid in excess of debt issuances and cash raised from common stock sales. In 2008, net cash provided from financing activities totaled \$375 million primarily due to long-term debt issuances and cash raised from common stock sales in excess of redemptions of securities and dividends paid. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for 2010 included increases of \$454 million in accumulated deferred income taxes, \$340 million in gross plant related to environmental mandates and transmission and distribution projects, \$124 million in prepaid pension costs, \$101 million in deferred charges related to income taxes, and a \$214 million decrease in cash and cash equivalents. In 2009, significant balance sheet changes included increases of \$340 million in cash primarily from collections on regulatory clauses. These cash collections correspondingly decreased current and deferred under recovered regulatory clause revenues by \$297 million and increased current and deferred over recovered regulatory clause revenues by \$204 million. Other changes include increases of \$939 million in gross plant related to environmental mandates and transmission and distribution projects and \$478 million in long-term debt.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.0% in 2010, 43.3% in 2009, and 42.5% 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. The Company has primarily utilized funds from operating cash flows, short-term debt, security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

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

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

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

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 \$154 million of cash and cash equivalents and \$1.3 billion of unused credit arrangements with banks, as described below. In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs.

The Company maintains committed lines of credit in the amount of \$1.3 billion, of which \$506 million will expire at various times during 2011. \$372 million of the credit facilities expiring in 2011 allow for the execution of term loans for an additional one-year period. \$765 million of credit facilities expire in 2012. A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds. During 2010, the Company remarketed \$307 million of pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support is \$798 million as of December 31, 2010.

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.

The Company had no commercial paper outstanding as of December 31, 2010 or December 31, 2009.

During 2010, the Company had an average of $7 million of commercial paper outstanding at a weighted average interest rate of 0.22% per annum and the maximum amount outstanding was $135 million. During 2009, the Company had an average of $30 million of commercial paper outstanding at a weighted average interest rate of 0.23% per annum and the maximum amount outstanding was $237 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 October 2010, the Company issued $250 million aggregate principal amount of Series 2010A 3.375% Senior Notes due October 1, 2020. The net proceeds were used for the redemption of $150 million aggregate principal amount of the Company's Series AA 5.625% Senior Notes due April 15, 2034 and for other general corporate purposes, including the Company's continuous construction program.

In December 2010, the Company's $100 million Series R 4.70% Senior Notes due December 1, 2010 matured.

Subsequent to December 31, 2010, the Company's $200 million Series HH 5.10% Senior Notes due February 1, 2011 matured.

Subsequent to December 31, 2010, the Company entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $200 million.

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

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At December 31, 2010, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $322 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $989 million of long-term variable interest rate exposure that has not been hedged at January 1, 2011 was 0.95%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $9.9 million at January 1, 2011. For further information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 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 retail fuel hedging program implemented per the guidelines of the Alabama PSC.

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

The changes in fair value of energy-related derivative contracts, 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 millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$(44)**	$(92)
Contracts realized or settled	**61**	123
Current period changes[(a)]	**(55)**	(75)
Contracts outstanding at the end of the period, assets (liabilities), net	**$(38)**	$(44)

(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 $6 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2010, the Company had a net hedge volume of 33.9 million mmBtu with a weighted average contract cost approximately $1.14 per mmBtu above market prices, and 36.3 million mmBtu at December 31, 2009 with a weighted average contract cost approximately $1.22 per mmBtu above market prices. All of the natural gas hedges 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. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are actively quoted, and thus fall into Level 2. See Note 10 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 millions)			
Level 1	$ -	$ -	$ -	$-
Level 2	(38)	(30)	(8)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(38)	$(30)	$(8)	$-

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service and Standard & Poor's, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

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

Capital Requirements and Contractual Obligations

The approved construction program of the Company includes a base level investment of $0.9 billion for 2011, $0.9 billion for 2012, and $1.1 billion for 2013. Over the next three years, the Company estimates spending $579 million on Plant Farley (including nuclear fuel), $886 million on distribution facilities, and $548 million on transmission additions. Also included in the Company's approved construction program are estimated environmental expenditures to comply with existing statutes and regulations of $47 million, $26 million, and $53 million for 2011, 2012, and 2013, respectively. The Company currently anticipates that additional environmental expenditures may be required to comply with anticipated new statutes and regulations. Such additional environmental expenditures are estimated to be in amounts up to $48 million, $108 million, and $354 million for 2011, 2012, and 2013, respectively. These potential incremental investments are not included in the approved construction program. See Note 7 to the financial statements under "Construction Program" for additional details. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of Nuclear Regulatory Commission requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." In addition to the funds required for the Company's construction program, approximately $950 million will be required by the end of 2013 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost securities and replace these obligations with lower cost capital if market conditions permit.

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

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2011	2012-2013	2014-2015	After 2015	Uncertain Timing [d]	Total
			(in millions)			
Long-term debt[a] –						
Principal	$ 200	$ 750	$ 54	$ 5,182	$ -	$ 6,186
Interest	290	536	483	4,308	-	5,617
Preferred and preference stock dividends[b]	39	79	79	-	-	197
Energy-related derivative obligations[c]	31	9	-	-	-	40
Operating leases	20	29	13	8	-	70
Unrecognized tax benefits and interest[d]	-	-	-	-	45	45
Purchase commitments[e] –						
Capital[f]	834	1,900	-	-	-	2,734
Limestone[g]	16	33	28	49	-	126
Coal	1,304	1,441	861	579	-	4,185
Nuclear fuel	83	94	86	222	-	485
Natural gas[h]	288	402	280	147	-	1,117
Purchased power	30	62	75	270		437
Long-term service agreements[i]	23	41	35	18		117
Pension and other postretirement benefit plans[j]	9	17	-	-	-	26
Total	$3,167	$5,393	$1,994	$10,783	$45	$21,382

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

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

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

(d) The timing related to the realization of $45 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 $1.4 billion, $1.2 billion, and $1.3 billion, respectively.

(f) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel. Such amounts exclude the Company's estimates of potential incremental investments to comply with anticipated new environmental regulations of up to $48 million, $108 million, and $354 million for 2011, 2012, and 2013, respectively. 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 certain of its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment.

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

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

(j) 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 and retail rates, customer growth, economic recovery, storm damage cost recovery and repairs, fuel cost recovery and other rate actions, environmental regulations and expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, 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 pending EPA civil action 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 and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- 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

Alabama Power Company 2010 Annual Report

	2010	2009	2008
		(in millions)	
Operating Revenues:			
Retail revenues	**$5,076**	$4,497	$4,862
Wholesale revenues, non-affiliates	**465**	620	712
Wholesale revenues, affiliates	**236**	237	308
Other revenues	**199**	175	195
Total operating revenues	**5,976**	5,529	6,077
Operating Expenses:			
Fuel	**1,851**	1,824	2,184
Purchased power, non-affiliates	**72**	88	179
Purchased power, affiliates	**208**	219	359
Other operations and maintenance	**1,418**	1,211	1,259
Depreciation and amortization	**606**	545	520
Taxes other than income taxes	**332**	322	307
Total operating expenses	**4,487**	4,209	4,808
Operating Income	**1,489**	1,320	1,269
Other Income and (Expense):			
Allowance for equity funds used during construction	**36**	79	46
Interest income	**17**	17	19
Interest expense, net of amounts capitalized	**(303)**	(298)	(279)
Other income (expense), net	**(30)**	(25)	(32)
Total other income and (expense)	**(280)**	(227)	(246)
Earnings Before Income Taxes	**1,209**	1,093	1,023
Income taxes	**463**	384	368
Net Income	**746**	709	655
Dividends on Preferred and Preference Stock	**39**	39	39
Net Income After Dividends on Preferred and Preference Stock	**$ 707**	$ 670	$ 616

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
Alabama Power Company 2010 Annual Report

	2010	2009	2008
		(in millions)	
Operating Activities:			
Net income	**$ 746**	$ 709	$ 655
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**694**	637	600
Deferred income taxes	**410**	(66)	127
Allowance for equity funds used during construction	**(36)**	(79)	(46)
Pension, postretirement, and other employee benefits	**(15)**	(8)	-
Pension and postretirement funding	**(55)**	(17)	(26)
Stock based compensation expense	**5**	4	3
Natural disaster reserve	**52**	55	16
Other, net	**(27)**	8	12
Changes in certain current assets and liabilities --			
-Receivables	**(29)**	310	(32)
-Fossil fuel stock	**(1)**	(77)	(134)
-Materials and supplies	**(20)**	(22)	(18)
-Other current assets	**(4)**	(16)	(1)
-Accounts payable	**(54)**	(19)	(9)
-Accrued taxes	**(140)**	24	37
-Accrued compensation	**28**	(32)	(5)
-Other current liabilities	**(181)**	193	-
Net cash provided from operating activities	**1,373**	1,604	1,179
Investing Activities:			
Property additions	**(903)**	(1,234)	(1,478)
Investment in restricted cash from pollution control bonds	**-**	(6)	(96)
Distribution of restricted cash from pollution control bonds	**18**	49	36
Nuclear decommissioning trust fund purchases	**(237)**	(245)	(301)
Nuclear decommissioning trust fund sales	**236**	244	300
Cost of removal net of salvage	**(44)**	(38)	(42)
Change in construction payables	**(45)**	26	42
Other investing activities	**(12)**	(25)	(61)
Net cash used for investing activities	**(987)**	(1,229)	(1,600)
Financing Activities:			
Increase (decrease) in notes payable, net	**-**	(25)	25
Proceeds --			
Common stock issued to parent	**-**	203	300
Capital contributions from parent company	**28**	24	21
Pollution control revenue bonds	**-**	79	265
Senior notes issuances	**250**	500	850
Redemptions --			
Preferred stock	**-**	-	(125)
Pollution control revenue bonds	**-**	-	(11)
Senior notes	**(250)**	(250)	(410)
Payment of preferred and preference stock dividends	**(39)**	(39)	(41)
Payment of common stock dividends	**(586)**	(523)	(491)
Other financing activities	**(3)**	(4)	(8)
Net cash provided from (used for) financing activities	**(600)**	(35)	375
Net Change in Cash and Cash Equivalents	**(214)**	340	(46)
Cash and Cash Equivalents at Beginning of Year	**368**	28	74
Cash and Cash Equivalents at End of Year	**$ 154**	$ 368	$ 28
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $14, $33 and $20 capitalized, respectively)	**$288**	$255	$259
Income taxes (net of refunds)	**188**	426	214
Noncash transactions - accrued property additions at year-end	**28**	74	107

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

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

Assets	**2010**	2009
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 154**	$ 368
Restricted cash	**18**	37
Receivables --		
Customer accounts receivable	**362**	322
Unbilled revenues	**153**	135
Under recovered regulatory clause revenues	**5**	37
Other accounts and notes receivable	**35**	34
Affiliated companies	**57**	62
Accumulated provision for uncollectible accounts	**(10)**	(10)
Fossil fuel stock, at average cost	**391**	395
Materials and supplies, at average cost	**346**	326
Vacation pay	**55**	54
Prepaid expenses	**208**	111
Other regulatory assets, current	**38**	34
Other current assets	**10**	6
Total current assets	**1,822**	1,911
Property, Plant, and Equipment:		
In service	**19,966**	18,575
Less accumulated provision for depreciation	**6,931**	6,559
Plant in service, net of depreciation	**13,035**	12,016
Nuclear fuel, at amortized cost	**283**	253
Construction work in progress	**547**	1,256
Total property, plant, and equipment	**13,865**	13,525
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**64**	60
Nuclear decommissioning trusts, at fair value	**552**	490
Miscellaneous property and investments	**71**	69
Total other property and investments	**687**	619
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**488**	387
Prepaid pension costs	**257**	133
Deferred under recovered regulatory clause revenues	**4**	-
Other regulatory assets, deferred	**675**	750
Other deferred charges and assets	**196**	199
Total deferred charges and other assets	**1,620**	1,469
Total Assets	**$17,994**	$17,524

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

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

Liabilities and Stockholder's Equity	**2010**	2009
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 200**	$ 100
Accounts payable --		
Affiliated	**210**	195
Other	**273**	328
Customer deposits	**86**	87
Accrued taxes --		
Accrued income taxes	**2**	15
Other accrued taxes	**32**	32
Accrued interest	**63**	65
Accrued vacation pay	**45**	45
Accrued compensation	**99**	71
Liabilities from risk management activities	**31**	38
Over recovered regulatory clause revenues	**22**	182
Other current liabilities	**41**	40
Total current liabilities	**1,104**	1,198
Long-Term Debt (See accompanying statements)	**5,987**	6,082
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,747**	2,293
Deferred credits related to income taxes	**85**	89
Accumulated deferred investment tax credits	**157**	165
Employee benefit obligations	**311**	388
Asset retirement obligations	**520**	491
Other cost of removal obligations	**701**	668
Other regulatory liabilities, deferred	**217**	169
Deferred over recovered regulatory clause revenues	**-**	22
Other deferred credits and liabilities	**87**	37
Total deferred credits and other liabilities	**4,825**	4,322
Total Liabilities	**11,916**	11,602
Redeemable Preferred Stock (See accompanying statements)	**342**	342
Preference Stock (See accompanying statements)	**343**	343
Common Stockholder's Equity (See accompanying statements)	**5,393**	5,237
Total Liabilities and Stockholder's Equity	**$17,994**	$17,524
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
Alabama Power Company 2010 Annual Report

	2010	2009	2010	2009
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts --				
Variable rate (3.39% at 1/1/11) due 2042	**$ 206**	$ 206		
Long-term notes payable --				
4.70% due 2010	**-**	100		
5.10% due 2011	**200**	200		
4.85% due 2012	**500**	500		
5.80% due 2013	**250**	250		
3.375% to 6.375% due 2016-2047	**3,875**	3,775		
Total long-term notes payable	**4,825**	4,825		
Other long-term debt --				
Pollution control revenue bonds --				
1.40% to 5.00% due 2030-2038	**367**	554		
Variable rates (0.26% to 0.44% at 1/1/11) due 2015-2038	**788**	601		
Total other long-term debt	**1,155**	1,155		
Unamortized debt premium (discount), net	**1**	(4)		
Total long-term debt (annual interest requirement -- $290.4 million)	**6,187**	6,182		
Less amount due within one year	**200**	100		
Long-term debt excluding amount due within one year	**5,987**	6,082	**49.6%**	50.7%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2010 and 2009
Alabama Power Company 2010 Annual Report

	2010	2009	**2010**	2009
	(in millions)		*(percent of total)*	
Redeemable Preferred Stock:				
Cumulative redeemable preferred stock				
$100 par or stated value -- 4.20% to 4.92%				
Authorized - 3,850,000 shares				
Outstanding - 475,115 shares	**48**	48		
$1 par value -- 5.20% to 5.83%				
Authorized - 27,500,000 shares				
Outstanding - 12,000,000 shares: $25 stated value				
(annual dividend requirement -- $18.1 million)	**294**	294		
Total redeemable preferred stock	**342**	342	**2.8**	2.8
Preference Stock:				
Authorized - 40,000,000 shares				
Outstanding - $1 par value -- 5.63% to 6.50%				
- 14,000,000 shares				
(non-cumulative) $25 stated value				
(annual dividend requirement -- $21.4 million)	**343**	343	**2.9**	2.9
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized: 40,000,000 shares				
Outstanding: 30,537,500 shares	**1,222**	1,222		
Paid-in capital	**2,156**	2,119		
Retained earnings	**2,022**	1,901		
Accumulated other comprehensive income (loss)	**(7)**	(5)		
Total common stockholder's equity	**5,393**	5,237	**44.7**	43.6
Total Capitalization	**$12,065**	$12,004	**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
Alabama Power Company 2010 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2007	18	$719	$2,065	$1,631	$(4)	$4,411
Net income after dividends on preferred and preference stock	-	-	-	616	-	616
Issuance of common stock	7	300	-	-	-	300
Capital contributions from parent company	-	-	26	-	-	26
Other comprehensive income (loss)	-	-	-	-	(6)	(6)
Cash dividends on common stock	-	-	-	(491)	-	(491)
Other	-	-	-	(2)	-	(2)
Balance at December 31, 2008	25	1,019	2,091	1,754	(10)	4,854
Net income after dividends on preferred and preference stock	-	-	-	670	-	670
Issuance of common stock	5	203	-	-	-	203
Capital contributions from parent company	-	-	28	-	-	28
Other comprehensive income (loss)	-	-	-	-	5	5
Cash dividends on common stock	-	-	-	(523)	-	(523)
Other	1	-	-	-	-	-
Balance at December 31, 2009	**31**	**1,222**	**2,119**	**1,901**	**(5)**	**5,237**
Net income after dividends on preferred and preference stock	**-**	**-**	**-**	**707**	**-**	**707**
Capital contributions from parent company	**-**	**-**	**37**	**-**	**-**	**37**
Other comprehensive income (loss)	**-**	**-**	**-**	**-**	**(2)**	**(2)**
Cash dividends on common stock	**-**	**-**	**-**	**(586)**	**-**	**(586)**
Balance at December 31, 2010	**31**	**$1,222**	**$2,156**	**$2,022**	**$(7)**	**$5,393**

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
Alabama Power Company 2010 Annual Report

	2010	2009	2008
		(in millions)	
Net income after dividends on preferred and preference stock	**$707**	$670	$616
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(2), and $(4), respectively	**-**	(3)	(8)
Reclassification adjustment for amounts included in net income, net of tax of $(1), $5, and $1, respectively	**(2)**	8	2
Total other comprehensive income (loss)	**(2)**	5	(6)
Comprehensive Income	**$705**	$675	$610

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets 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, including the Company's Plant Farley.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Alabama Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $371 million, $325 million, and $321 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 an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $218 million, $183 million, and $196 million during 2010, 2009, and 2008, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses, which were $11 million in 2010, $10 million in 2009, and $11 million in 2008. See Note 4 for additional information.

Southern Company's 30% ownership interest in Alabama Fuel Products, LLC (AFP), which produced synthetic fuel, was terminated in July 2006. The Company had an agreement with an indirect subsidiary of Southern Company that provided services for AFP. Under this agreement, the Company provided certain accounting functions, including processing and paying fuel transportation invoices, and the Company was reimbursed for its expenses. Amounts billed under this agreement totaled approximately $1 million in

2008. In addition, the Company purchased synthetic fuel from AFP for use at several of the Company's plants. Synthetic fuel purchases totaled $6 million in 2008.

The Company had an agreement with Southern Power under which the Company operated and maintained Plant Harris at cost. On August 1, 2007, that agreement was terminated and replaced with a service agreement under which the Company provides to Southern Power specifically requested services. In 2010, 2009, and 2008, the Company billed Southern Power $1 million, $1 million, and $1 million, respectively, under these agreements. Under a power purchase agreement (PPA) with Southern Power, the Company's purchased power costs from Plant Harris in 2010, 2009, and 2008 totaled $15 million, $62 million, and $63 million, respectively. The Company also provides the fuel, at cost, associated with the PPA. The fuel cost recognized by the Company was $21 million in 2010, $63 million in 2009, and $120 million in 2008. The Company recorded no prepaid capacity expenses in 2010 due to the expiration of the PPA with Southern Power in May 2010. The Company recorded $8.3 million of prepaid capacity expenses included in other deferred charges and other assets in the balance sheets at December 31, 2009 and 2008. See Note 3 under "Retail Regulatory Matters" and Note 7 under "Purchased Power Commitments" for additional information.

The Company has an agreement with Gulf Power under which the Company will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA. In March 2009, Gulf Power entered into a PPA for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. The total cost committed by the Company related to the upgrades is approximately $82 million over the next four years. The Company expects to recover a majority of these costs from Gulf Power over the next ten years.

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

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

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

Regulatory Assets and Liabilities

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

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

	2010	2009	Note
	(in millions)		
Deferred income tax charges	**$ 488**	$ 387	(a, j, l)
Loss on reacquired debt	**74**	74	(b)
Vacation pay	**55**	54	(c, k)
Under/(over) recovered regulatory clause revenues	**(13)**	(166)	(d)
Fuel-hedging (realized and unrealized) losses	**39**	45	(e)
Other assets	**30**	8	(f, g)
Asset retirement obligations	**(77)**	(43)	(a)
Other cost of removal obligations	**(701)**	(668)	(a)
Deferred income tax credits	**(85)**	(89)	(a)
Fuel-hedging (realized and unrealized) gains	**(1)**	(1)	(e)
Mine reclamation and remediation	**(10)**	(12)	(h)
Nuclear outage	**-**	(27)	(d)
Deferred purchased power	**-**	(8)	(g)
Natural disaster reserve	**(127)**	(75)	(i)
Other liabilities	**(3)**	(3)	(d)
Retiree benefit plans	**569**	657	(j, k)
Total assets (liabilities), net	**$ 238**	$ 133	

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

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

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

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

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

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

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

(g) Recovered over the life of the PPA for periods up to 13.5 years.

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

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

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

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

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

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract periods. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters – Fuel Cost Recovery" and "Retail Regulatory Matters – Rate CNP" for additional information.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less 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 millions)	
Generation	**$10,598**	$ 9,627
Transmission	**2,826**	2,702
Distribution	**5,267**	5,046
General	**1,262**	1,187
Plant acquisition adjustment	**12**	12
Total plant in service	**$19,965**	$18,574

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders. During 2010, the Company accrued estimated nuclear refueling outage costs in advance of the unit's next refueling outage. The refueling cycle is 18 months for each unit. During 2010, the Company accrued $53 million for the applicable refueling cycles and paid $80 million for outages at Plant Farley Units 1 and 2. At December 31, 2010, the reserve balance was zero.

On August 17, 2010, the Alabama PSC approved the Company's request to stop accruing for nuclear refueling outage costs in advance of the refueling outages when the most recent 18-month cycle ended in December 2010 and to begin deferring nuclear outage expenses. The amortization will begin after each outage has occurred and the associated outage expenses are known. The first 18-month amortization cycle for expenses associated with the fall 2011 outage will begin in January 2012. The second cycle will begin in July 2012 for expenses associated with the spring 2012 outage.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.3% in 2010 and 3.2% in 2009 and 2008. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Asset Retirement Obligations and Other Costs of Removal

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

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facility, Plant Farley. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" for further information on amounts included in rates.

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

	2010	2009
	(in millions)	
Balance at beginning of year	**$491**	$461
Liabilities incurred	**-**	-
Liabilities settled	**(2)**	(1)
Accretion	**33**	31
Cash flow revisions [(a)]	**(2)**	-
Balance at end of year	**$520**	$491

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

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (the Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities and the Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Alabama PSC, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require, except for investments tied to market indices or other mutual funds, that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the Company's management. The Funds' managers are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

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

At December 31, 2010, investment securities in the Funds totaled $552 million consisting of equity securities of $406 million, debt securities of $139 million, and $7 million of other securities. At December 31, 2009, investment securities in the Funds totaled $488 million consisting of equity securities of $346 million, debt securities of $134 million, and $9 million of other securities. These amounts exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

Sales of the securities held in the Funds resulted in cash proceeds of $236 million, $244 million, and $300 million in 2010, 2009, and 2008, respectively, all of which were reinvested. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $65 million, of which $31 million related to securities held in the Funds at December 31, 2010. For 2009, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $96 million, of which $80 million related to securities held in the Funds at December 31, 2009. For 2008, fair value reductions, including reinvested interest and dividends and excluding the Funds' expenses, were $(134) million. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed a plan with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2010, the accumulated provisions for decommissioning were as follows:

	(in millions)
External trust funds	$553
Internal reserves	24
Total	$577

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

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

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

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

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

Allowance for Funds Used During Construction (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. All current construction costs are included in retail rates. The composite rate used to determine the amount of AFUDC was 9.4% in 2010 and 9.2% in 2009 and 2008. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 6.3% in 2010, 14.9% in 2009, and 9.4% in 2008.

Impairment of Long-Lived Assets and Intangibles

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

Natural Disaster Reserve

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

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

On August 20, 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

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 Alabama PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Alabama PSC-approved fuel hedging program. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company 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 after dividends on preferred and preference stock, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information. However, the Company is not considered the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as other investments, and the related loans from the trusts are reflected as long-term debt in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2010, the Company contributed approximately $38 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 postretirement trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2011, other postretirement trust contributions are expected to total approximately $9 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 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	**5.52%**	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	**7.43**	7.52	7.66

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 millions)	
Benefit obligation	$32	$28
Service and interest costs	2	1

Pension Plans

The total accumulated benefit obligation for the pension plans was $1.7 billion in 2010 and $1.6 billion 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 millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$1,675**	$1,460
Service cost	**41**	34
Interest cost	**97**	96
Benefits paid	**(81)**	(77)
Actuarial loss (gain)	**47**	162
Balance at end of year	**1,779**	1,675
Change in plan assets		
Fair value of plan assets at beginning of year	**1,712**	1,539
Actual return (loss) on plan assets	**258**	245
Employer contributions	**44**	5
Benefits paid	**(81)**	(77)
Fair value of plan assets at end of year	**1,933**	1,712
Prepaid pension asset, net	**$ 154**	$ 37

At December 31, 2010, the projected benefit obligations for the qualified and non-qualified pension plans were $1.7 billion and $103 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 millions)	
Prepaid pension costs	**$257**	$133
Other regulatory assets, deferred	**497**	549
Other current liabilities	**(7)**	(6)
Employee benefit obligations	**(96)**	(90)

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 millions)	
Prior service cost	**$ 41**	$ 50	**$ 9**
Net (gain) loss	**456**	499	**4**
Other regulatory assets, deferred	**$497**	$549	

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 millions)
Balance at December 31, 2008	$479
Net loss	79
Change in prior service costs	1
Reclassification adjustments:	
Amortization of prior service costs	(9)
Amortization of net gain	(1)
Total reclassification adjustments	(10)
Total change	70
Balance at December 31, 2009	549
Net gain	**(42)**
Change in prior service costs	**1**
Reclassification adjustments:	
Amortization of prior service costs	**(9)**
Amortization of net gain	**(2)**
Total reclassification adjustments	**(11)**
Total change	**(52)**
Balance at December 31, 2010	**$497**

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

	2010	2009	2008
		(in millions)	
Service cost	**$ 41**	$ 34	$ 35
Interest cost	**97**	96	87
Expected return on plan assets	**(168)**	(164)	(160)
Recognized net (gain) loss	**2**	1	2
Net amortization	**9**	9	10
Net periodic pension cost (income)	**$ (19)**	$ (24)	$ (26)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2010, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2011	$ 90
2012	95
2013	99
2014	103
2015	108
2016 to 2020	596

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 millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 461**	$ 446
Service cost	**6**	6
Interest cost	**26**	29
Benefits paid	**(26)**	(26)
Actuarial loss (gain)	**(16)**	19
Plan amendments	**-**	(15)
Retiree drug subsidy	**3**	2
Balance at end of year	**454**	461
Change in plan assets		
Fair value of plan assets at beginning of year	**295**	252
Actual return (loss) on plan assets	**35**	47
Employer contributions	**16**	20
Benefits paid	**(23)**	(24)
Fair value of plan assets at end of year	**323**	295
Accrued liability	**$(131)**	$(166)

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 millions)	
Regulatory assets	**$ 72**	$ 108
Employee benefit obligations	**(131)**	(166)

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 millions)	
Prior service cost	**$ 30**	$ 33	**$ 4**
Net (gain) loss	**37**	67	**-**
Transition obligation	**5**	8	**3**
Regulatory assets	**$ 72**	$108	

The changes in the balance of regulatory assets 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
	(in millions)
Balance at December 31, 2008	$135
Net gain	(4)
Change in prior service costs/transition obligation	(15)
Reclassification adjustments:	
Amortization of transition obligation	(4)
Amortization of prior service costs	(4)
Amortization of net gain	-
Total reclassification adjustments	(8)
Total change	(27)
Balance at December 31, 2009	108
Net gain	**(29)**
Change in prior service costs/transition obligation	**-**
Reclassification adjustments:	
Amortization of transition obligation	**(3)**
Amortization of prior service costs	**(4)**
Amortization of net gain	**-**
Total reclassification adjustments	**(7)**
Total change	**(36)**
Balance at December 31, 2010	**$ 72**

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

	2010	2009	2008
		(in millions)	
Service cost	**$ 6**	$ 6	$ 7
Interest cost	**26**	29	29
Expected return on plan assets	**(25)**	(24)	(22)
Net amortization	**7**	8	9
Net postretirement cost	**$ 14**	$ 19	$ 23

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 $8 million, $9 million, and $11 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 millions)	
2011	$ 29	$ (3)	$ 26
2012	31	(3)	28
2013	33	(3)	30
2014	35	(3)	32
2015	36	(4)	32
2016 to 2020	184	(22)	162

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	47%	**41%**	42%
International equity	12	**16**	16
Domestic fixed income	32	**36**	35
Special situations	1	**-**	-
Real estate investments	5	**4**	4
Private equity	3	**3**	3
Total	100%	**100%**	100%

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

Investment Strategies

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

- ***Domestic equity.*** A mix of large and small capitalization stocks with an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance.*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.

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

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

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 millions)		
Assets:				
Domestic equity*	$339	$141	$ -	$ 480
International equity*	439	44	-	483
Fixed income:				
U.S. Treasury, government, and agency bonds	-	127	-	127
Mortgage- and asset-backed securities	-	34	-	34
Corporate bonds	-	85	-	85
Pooled funds	-	3	-	3
Cash equivalents and other	1	104	-	105
Special situations	-	-	-	-
Real estate investments	53	-	166	219
Private equity	-	-	169	169
Total	$832	$538	$335	$1,705
Liabilities:				
Derivatives	(1)	-	-	(1)
Total	$831	$538	$335	$1,704

*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 were as follows:

	2010		2009	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in millions)		
Beginning balance	**$166**	**$169**	$254	$148
Actual return on investments:				
Related to investments held at year end	**14**	**9**	(72)	13
Related to investments sold during the year	**3**	**3**	(20)	3
Total return on investments	**17**	**12**	(92)	16
Purchases, sales, and settlements	**8**	**(1)**	4	5
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$191**	**$180**	$166	$169

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

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

	Fair Value Measurements Using			
As of December 31, 2009:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$54	$ 8	$ -	$ 62
International equity*	24	2	-	26
Fixed income:				
U.S. Treasury, government, and agency bonds	-	7	-	7
Mortgage- and asset-backed securities	-	2	-	2
Corporate bonds	-	5	-	5
Pooled funds	-	-	-	-
Cash equivalents and other	-	23	-	23
Trust-owned life insurance	-	144	-	144
Special situations	-	-	-	-
Real estate investments	3	-	9	12
Private equity	-	-	10	10
Total	$81	$191	$19	$291

*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 were as follows:

	2010		2009	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in millions)			
Beginning balance	**$ 9**	**$10**	$15	$8
Actual return on investments:				
Related to investments held at year end	**1**	**-**	(5)	2
Related to investments sold during the year	**-**	**-**	(1)	-
Total return on investments	**1**	**-**	(6)	2
Purchases, sales, and settlements	**-**	**(1)**	-	-
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$10**	**$ 9**	$9	$10

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 $18 million, $19 million, and $18 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 the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to each of the traditional operating companies. After the Company was dismissed from the original action, the EPA filed a separate action in January 2001 against the Company in the U.S. District Court for the Northern District of Alabama. In the lawsuit against the Company, the EPA alleges that NSR violations occurred at five coal-fired generating facilities operated by the Company. The civil action requests 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. The separate action against the Company is ongoing.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between the Company and the EPA, resolving a portion of the Company's 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 the Company 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 the Company, leaving only three claims for summary disposition or trial, including the claim relating to a facility co-owned by Mississippi Power. 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.

Nuclear Fuel Disposal Costs

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

In July 2007, the U.S. Court of Federal Claims awarded the Company approximately $17 million, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plant Farley from 1998 through 2004. In November 2007, the government's motion for reconsideration was denied. In January 2008, the government filed an appeal and, in February 2008, filed a motion to stay the appeal, which the U.S. Court of Appeals for the Federal Circuit granted in April 2008. On May 5, 2010, the U.S. Court of Appeals for the Federal Circuit lifted the stay.

In April 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim), due to the government's alleged continuing breach of contract. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2010 for either claim. The final outcome of these matters cannot be determined at this time, but no material impact on the Company's net income is expected as any damage amounts collected from the government are expected to be returned to customers.

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

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 $141 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

Rate RSE

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

The Rate RSE increase for 2010 was 3.24%, or $152 million annually, and was effective in January 2010. In December 2010, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2011 and earnings were within the specified return range. Consequently, the retail rates will remain unchanged in 2011 under Rate RSE. Under the terms of Rate RSE, the maximum increase for 2012 cannot exceed 5.00%.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under a rate certificated new plant (Rate CNP). There was no adjustment to the Rate CNP to recover certificated PPA costs in 2008 or 2009. Effective April 2010, Rate CNP was reduced by approximately $70 million annually, primarily due to the expiration on May 31, 2010 of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. It is estimated that there will be a slight decrease to the current Rate CNP effective April 2011.

Rate CNP also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism is based on forward looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Retail rates increased approximately 2.4% in January 2008 and 4.3% in January 2010 due to environmental costs. In October 2008, the Company agreed to defer collection of any increase in rates under this portion of Rate CNP, which permits recovery of costs associated with environmental laws and regulations, from 2009 until 2010. The deferral of the retail rate adjustments had an immaterial impact on annual cash flows, and had no significant effect on the Company's revenues or net income. On December 1, 2010, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under rate certificated new plant environmental. The filing reflects an incremental increase in the revenue requirement associated with such environmental compliance, which would be recoverable in the billing months of January 2011 through December 2011. In order to afford additional rate stability to customers as the economy continues to recover from the recession, the Alabama PSC ordered on January 4, 2011 that the Company leave in effect for 2011 the factors associated with the Company's environmental compliance costs for the year 2010. Any recoverable amounts associated with 2011 will be reflected in the 2012 filing. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates under rate energy cost recovery (Rate ECR) as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per kilowatt-hour (KWH) sales. The Rate ECR factor as of January 1, 2011 is 2.403 cents per KWH. Effective with billings beginning in April 2011, the Rate ECR factor will be 2.681 cents per KWH.

As of December 31, 2010, the Company had an under recovered fuel balance of approximately $4 million which is included in deferred under recovered regulatory clause revenues in the balance sheets. As of December 31, 2009, the Company had an over recovered fuel balance of approximately $200 million, of which approximately $22 million was included in deferred over recovered regulatory clause revenues in the balance sheets. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any return of the over recovered fuel costs or recovery of under recovered fuel costs.

Natural Disaster Reserve

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

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

On August 20, 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

For the year ended December 31, 2010, the Company accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. For the year ended December 31, 2009, the Company accrued an additional $40 million to the NDR, resulting in an accumulated balance of approximately $75 million. These accruals are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, interest expense, and a return on equity, whether or not SEGCO has any capacity and energy available. The term of the contract extends automatically for two-year periods, subject to either party's right to cancel upon two years' notice. The Company's share of purchased power totaled $101 million in 2010, $82 million in 2009, and $124 million in 2008, and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

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

At December 31, 2010, the capitalization of SEGCO consisted of $90 million of equity and $75 million of long-term debt on which the annual interest requirement is $3 million. SEGCO paid dividends of $5 million in 2010, none in 2009, and $8 million in 2008, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

In addition to the Company's ownership of SEGCO, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2010 is as follows:

Facility	Total Megawatt Capacity	Company Ownership	Amount of Investment	Accumulated Depreciation
			(in millions)	
Greene County	500	60.00% (1)	$ 140	$ 76
Plant Miller Units 1 and 2	1,320	91.84% (2)	1,253	477

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

At December 31, 2010, the Company's portion of Plant Miller construction work in progress was $125 million.

The Company has contracted to operate and maintain the jointly owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

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

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2010	2009	2008
		(in millions)	
Federal –			
Current	**$ 52**	$374	$198
Deferred	**333**	(41)	121
	$385	$333	$319
State –			
Current	**$ 1**	$ 76	$ 43
Deferred	**77**	(25)	6
	78	51	49
Total	**$463**	$384	$368

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 millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$2,415**	$2,010
Property basis differences	**396**	376
Premium on reacquired debt	**31**	30
Pension and other benefits	**210**	184
Fuel clause under recovered	**10**	-
Regulatory assets associated with employee benefit obligations	**239**	295
Regulatory assets associated with asset retirement obligations	**220**	208
Other	**85**	82
Total	**3,606**	3,185
Deferred tax assets:		
Federal effect of state deferred taxes	**177**	88
State effect of federal deferred taxes	**50**	107
Unbilled revenue	**41**	29
Storm reserve	**41**	23
Pension and other benefits	**264**	334
Other comprehensive losses	**8**	9
Fuel clause over recovered	**-**	75
Asset retirement obligations	**220**	208
Other	**87**	93
Total	**888**	966
Total deferred tax liabilities, net	**2,718**	2,219
Portion included in current assets (liabilities), net	**29**	74
Accumulated deferred income taxes	**$2,747**	$2,293

At December 31, 2010, the Company's tax-related regulatory assets and liabilities were $488 million and $85 million, respectively. These assets are attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest. In 2010, the Company deferred $21 million as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of health care costs that are covered by federal Medicare subsidy payments. The Company will amortize the regulatory asset to income tax expense over the average remaining service period which may range up to 15 years, as approved by the Alabama PSC. These liabilities are attributable to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $8 million in each of 2010, 2009, and 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 tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2010	2009	2008
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**4.2**	3.0	3.1
Non-deductible book depreciation	**0.8**	0.8	0.9
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.2)	(0.1)
AFUDC-equity	**(1.0)**	(2.5)	(1.6)
Production activities deduction	**-**	(0.8)	(0.5)
Other	**(0.6)**	(0.2)	(0.8)
Effective income tax rate	**38.3%**	35.1%	36.0%

State income tax, net of federal deduction increased in 2010 due to a decrease in the state deduction for federal income taxes paid, which is a result of increased bonus depreciation and pension contributions.

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

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The 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 $37 million, resulting in a balance of $43 million as of December 31, 2010.

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

	2010	2009	2008
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 6**	$3	$5
Tax positions from current periods	**6**	2	1
Tax positions from prior periods	**31**	1	(2)
Reductions due to settlements	**-**	-	(1)
Reductions due to expired statute of limitations	**-**	-	-
Balance at end of year	**$43**	$6	$3

The tax positions increases from current periods and from prior periods relate primarily to the tax accounting method change for repairs and other miscellaneous uncertain tax positions. See Note 3 under "Income Tax Matters – Tax Method of Accounting for Repairs" for additional information.

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

	2010	2009	2008
		(in millions)	
Tax positions impacting the effective tax rate	**$ 6**	$6	$3
Tax positions not impacting the effective tax rate	**37**	-	-
Balance of unrecognized tax benefits	**$43**	$6	$3

The tax positions impacting the effective tax rate primarily relate to the production activities deduction tax position. 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 – Tax Method of Accounting for Repairs" for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2010	2009	2008
		(in millions)	
Interest accrued at beginning of year	**$0.3**	$0.3	$0.4
Interest reclassified due to settlements	**-**	-	(0.3)
Interest accrued during the year	**1.2**	-	0.2
Balance at end of year	**$1.5**	$0.3	$0.3

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

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The 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

Long-Term Debt Payable to Affiliated Trusts

The Company has formed certain wholly-owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as long-term debt payable. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2010, preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

At December 31, 2010 and 2009, the Company had scheduled maturities of senior notes due within one year totaling $200 million and $100 million, respectively.

Maturities of senior notes through 2015 applicable to total long-term debt are as follows: $200 million in 2011; $500 million in 2012; $250 million in 2013; and none in 2014 and 2015.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds or installment purchases of solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred no obligations related to the issuance of pollution control revenue bonds in 2010. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Senior Notes

The Company issued a total of $250 million of unsecured senior notes in 2010. The proceeds of these issuances were used to redeem $150 million aggregate principle amount of the Company's Series AA 5.625% Senior Notes due April 15, 2034 and for other general corporate purposes, including the Company's continuous construction program.

In December 2010, the Company's $100 million Series R 4.70% Senior Notes due December 1, 2010 matured.

Subsequent to December 31, 2010, the Company's $200 million Series HH 5.10% Senior Notes due February 1, 2011 matured.

At December 31, 2010 and 2009, the Company had $4.8 billion and $4.8 billion, respectively, of senior notes outstanding. These senior notes are effectively subordinate to all secured debt of the Company which amounted to approximately $153 million at December 31, 2010.

Preference and Common Stock

In 2010, the Company issued no new shares of preference stock or common stock.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized and outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The preferred stock and Class A preferred stock of the Company contain a feature that allows the holders to elect a majority of the Company's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The preference stock does not contain such a provision that would allow the holders to elect a majority of the Company's board. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preferred stock, Class A preferred stock, and preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance).

Dividend Restrictions

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

Assets Subject to Lien

The Company has granted liens on certain property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $153 million as of December 31, 2010. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Bank Credit Arrangements

The Company maintains committed lines of credit in the amount of $1.3 billion, of which $506 million will expire at various times during 2011. $372 million of the credit facilities expiring in 2011 allow for the execution of term loans for an additional one-year period. $765 million of credit facilities expire in 2012. A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds. During 2010, the Company remarketed $307 million of pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support is $798 million as of December 31, 2010.

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

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2010, the Company was in compliance with the debt limit covenants. In addition, the credit arrangements typically contain cross default provisions that would be triggered if the Company defaulted on other indebtedness (including guarantee obligations) above a specified threshold. None of the arrangements contain material adverse change clauses at the time of borrowings.

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. In addition, the Company borrows from time to time through uncommitted credit arrangements. As of December 31, 2010 and 2009, the Company had no commercial paper outstanding. During 2010 and 2009, the maximum amount outstanding for commercial paper was $135 million and $237 million, respectively. The average amount outstanding in 2010 and 2009 was $7 million and $30 million, respectively. The weighted average annual interest rate on commercial paper was 0.22% in 2010 and 0.23% in 2009. Short-term borrowings are included in notes payable in the balance sheets.

At December 31, 2010, the Company had regulatory approval to have outstanding up to $2.0 billion of short-term borrowings.

7. COMMITMENTS

Construction Program

The approved construction program of the Company includes a base level investment of $0.9 billion in 2011, $0.9 billion in 2012, and $1.1 billion in 2013. These amounts include $83 million, $59 million, and $35 million in 2011, 2012, and 2013, respectively, for construction expenditures related to contractual purchase commitments for nuclear fuel included herein under "Fuel Commitments." Also included in the Company's approved construction program are estimated environmental expenditures to comply with existing statutes and regulations of $47 million, $26 million, and $53 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; changes in environmental statutes and regulations; changes in generating plants, including unit retirement and replacement decisions, to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; storm impacts; 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. At December 31, 2010, significant purchase commitments were outstanding in connection with the ongoing construction program. The Company has no generating plants under construction. Construction of new transmission and distribution facilities and capital improvements, including those to meet environmental standards for existing generation, transmission, and distribution facilities, will continue.

Long-Term Service Agreements

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

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments to GE, which are subject to price escalation, are made at various intervals based on actual operating hours of the respective units. Total remaining payments to GE under these agreements for facilities owned are currently estimated at $117 million over the remaining life of the agreements, which are currently estimated to range up to six years. However, the LTSAs contain various cancellation provisions at the option of the Company. Payments made to GE prior to the performance of any planned maintenance are recorded as either prepayments or other deferred charges and assets in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 2.6 million tons, equating to approximately $126 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are $16 million in 2011, $16 million in 2012, $17 million in 2013, $17 million in 2014, and $11 million in 2015.

Fuel Commitments

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

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2011	$ 288	$1,304	$ 83
2012	227	832	59
2013	175	609	35
2014	156	424	43
2015	124	437	43
2016 and thereafter	147	579	222
Total commitments	$1,117	$4,185	$485

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense amounted to $79 million in 2010, $78 million in 2009, and $70 million in 2008.

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.

Purchased Power Commitments

The Company has entered into various long-term commitments for the purchase of capacity and energy. Total estimated minimum long-term obligations at December 31, 2010 were as follows:

	Commitments
	Non-Affiliated
	(in millions)
2011	$ 30
2012	31
2013	31
2014	37
2015	38
2016 and thereafter	270
Total commitments	$437

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

Operating Leases

The Company has entered into rental agreements for coal rail cars, vehicles, and other equipment with various terms and expiration dates. These expenses amounted to $25 million in 2010, $27 million in 2009, and $26 million in 2008. Of these amounts, $20 million, $20 million, and $19 million for 2010, 2009, and 2008, respectively, relate to the rail car leases and are recoverable through the Company's Rate ECR.

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

	Minimum Lease Payments		
	Rail Cars	Vehicles & Other	Total
		(in millions)	
2011	$16	$ 4	$20
2012	15	2	17
2013	11	1	12
2014	6	1	7
2015	5	1	6
2016 and thereafter	7	1	8
Total *	$60	$10	$70

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

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. The Company's maximum obligations under these leases are $1 million in 2012, $39 million in 2013, $8 million in 2014, $5 million in 2015, and $4 million in 2016. Upon termination of the leases, the Company has the option to negotiate an extension, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

At December 31, 2010, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities and issuance of senior notes, as discussed in Note 4, and to certain residual values of leased assets as described above in "Operating Leases."

8. STOCK COMPENSATION

Stock 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 1,313 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	8,749,474	$31.74
Granted	1,532,979	31.25
Exercised	(1,512,059)	27.76
Cancelled	(25,410)	31.33
Outstanding at December 31, 2010	**8,744,984**	**$ 32.35**
Exercisable at December 31, 2010	**5,920,732**	**$ 32.61**

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 $52 million and $33 million, respectively.

As of December 31, 2010, there was $1 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 10 months.

For the years ended December 31, 2010, 2009, and 2008, total compensation cost for stock option awards recognized in income was $3 million, $4 million, and $3 million, respectively, with the related tax benefit also recognized in income of $1 million, $1 million, and $1 million, respectively.

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

The total intrinsic value of options exercised during the years ended December 31, 2010, 2009, and 2008 was $12 million, $2 million, and $5 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $4 million, $1 million, and $2 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 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, 166,725 performance share units were granted to the Company's employees with a weighted-average grant date fair value of $30.13. During 2010, 14,923 performance share units were forfeited by the Company's employees resulting in 151,802 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 $1 million, with the related tax benefit also recognized in income of $1 million. As of December 31, 2010, there was $3 million of total unrecognized compensation cost related to performance share award units that will be recognized over the next two years.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $235 million per incident but not more than an aggregate of $35 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.3 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

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

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $42 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes. In the event of a loss, the amount of insurance available may not be adequate to cover property damage and other incurred expenses.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

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

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 2	$ -	$ 2
Nuclear decommissioning trusts:[(a)]				
Domestic equity	347	59	-	406
U.S. Treasury and government agency securities	20	7	-	27
Corporate bonds	-	82	-	82
Mortgage and asset backed securities	-	30	-	30
Other	-	7	-	7
Cash equivalents and restricted cash	109	-	-	109
Total	$476	$187	$ -	$663
Liabilities:				
Energy-related derivatives	$ -	$ 40	$ -	$ 40

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

Valuation Methodologies

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

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

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

As of December 31, 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 millions)			
Nuclear decommissioning trusts:				
Trust-owned life insurance	$ 86	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	109	None	Daily	Not applicable

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

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

As of December 31, 2010 and 2009, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2010	**$6,187**	**$6,463**
2009	$6,182	$6,357

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

11. DERIVATIVES

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

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Alabama PSC, through the use of financial derivative contracts, 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 three methods:

- *Regulatory Hedges* **–** Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *Cash Flow Hedges* **–** Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* **–** Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 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 millions)		
34	2015	-

*mmBtu – million British thermal units

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2011 are immaterial.

Interest Rate Derivatives

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

At December 31, 2010, the Company did not have any interest rate derivatives outstanding. Subsequent to December 31, 2010, the Company entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $200 million.

The estimated pre-tax gains that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2011 is $1 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

Derivative Financial Statement Presentation and Amounts

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

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2010**	2009	**Balance Sheet Location**	**2010**	2009
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$1**	$1	Liabilities from risk management activities	**$31**	$34
	Other deferred charges and assets	**1**	-	Other deferred credits and liabilities	**9**	11
Total derivatives designated as hedging instruments for regulatory purposes		**$2**	$1		**$40**	$45
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**$ -**	$ -	Liabilities from risk management activities	**$ -**	$ 4
Total		**$2**	$1		**$40**	$49

All derivative instruments are measured at fair value. See Note 10 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 millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$(31)**	$(34)	Other current liabilities	**$1**	$1
	Other regulatory assets, deferred	**(9)**	(11)	Other regulatory liabilities, deferred	**1**	-
Total energy-related derivative gains (losses)		**$(40)**	$(45)		**$2**	$1

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 millions)				*(in millions)*		
Interest rate derivatives	**$ -**	$(5)	$(11)	Interest expense, net of amounts capitalized	**$3**	$(12)	$(3)

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 $6 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 million.

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

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2010 and 2009 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2010	**$1,495**	**$399**	**$203**
June 2010	**1,462**	**389**	**190**
September 2010	**1,706**	**497**	**259**
December 2010	**1,313**	**204**	**55**
March 2009	$1,340	$299	$146
June 2009	1,366	349	177
September 2009	1,592	483	261
December 2009	1,231	189	86

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

[This page intentionally left blank]

SELECTED FINANCIAL AND OPERATING DATA 2006-2010

Alabama Power Company 2010 Annual Report

	2010	2009	2008	2007	2006
Operating Revenues **(in millions)**	**$5,976**	$5,529	$6,077	$5,360	$5,015
Net Income after Dividends					
on Preferred and Preference Stock **(in millions)**	**$707**	$670	$616	$580	$518
Cash Dividends					
on Common Stock **(in millions)**	**$586**	$523	$491	$465	$441
Return on Average Common Equity **(percent)**	**13.31**	13.27	13.30	13.73	13.23
Total Assets **(in millions)**	**$17,994**	$17,524	$16,536	$15,747	$14,655
Gross Property Additions **(in millions)**	**$956**	$1,323	$1,533	$1,203	$961
Capitalization **(in millions)**:					
Common stock equity	**$5,393**	$5,237	$4,854	$4,411	$4,032
Preference stock	**343**	343	343	343	147
Redeemable preferred stock	**342**	342	342	340	465
Long-term debt	**5,987**	6,082	5,605	4,750	4,148
Total (excluding amounts due within one year)	**$12,065**	$12,004	$11,144	$9,844	$8,792
Capitalization Ratios **(percent)**:					
Common stock equity	**44.7**	43.6	43.6	44.8	45.9
Preference stock	**2.9**	2.9	3.1	3.5	1.7
Redeemable preferred stock	**2.8**	2.8	3.0	3.4	5.3
Long-term debt	**49.6**	50.7	50.3	48.3	47.1
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers **(year-end)**:					
Residential	**1,235,128**	1,229,134	1,220,046	1,207,883	1,194,696
Commercial	**197,336**	198,642	211,119	216,830	214,723
Industrial	**5,770**	5,912	5,906	5,849	5,750
Other	**782**	780	775	772	766
Total	**1,439,016**	1,434,468	1,437,846	1,431,334	1,415,935
Employees **(year-end)**	**6,552**	6,842	6,997	6,980	6,796

	2010	2009	2008	2007	2006
Operating Revenues (in millions):					
Residential	**$2,283**	$1,962	$1,998	$1,834	$1,664
Commercial	**1,535**	1,430	1,459	1,314	1,172
Industrial	**1,231**	1,080	1,381	1,238	1,140
Other	**27**	25	24	21	20
Total retail	**5,076**	4,497	4,862	4,407	3,996
Wholesale - non-affiliates	**465**	620	712	627	635
Wholesale - affiliates	**236**	237	308	144	215
Total revenues from sales of electricity	**5,777**	5,354	5,882	5,178	4,846
Other revenues	**199**	175	195	182	169
Total	**$5,976**	$5,529	$6,077	$5,360	$5,015
Kilowatt-Hour Sales (in millions):					
Residential	**20,417**	18,071	18,380	18,874	18,633
Commercial	**14,719**	14,186	14,551	14,761	14,355
Industrial	**20,622**	18,555	22,075	22,806	23,187
Other	**216**	218	201	201	199
Total retail	**55,974**	51,030	55,207	56,642	56,374
Wholesale - non-affiliates	**8,655**	14,317	15,204	15,769	15,979
Wholesale - affiliates	**6,074**	6,473	5,256	3,241	5,145
Total	**70,703**	71,820	75,667	75,652	77,498
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.18**	10.86	10.87	9.71	8.93
Commercial	**10.43**	10.08	10.03	8.90	8.17
Industrial	**5.97**	5.82	6.26	5.43	4.92
Total retail	**9.07**	8.81	8.81	7.78	7.09
Wholesale	**4.76**	4.12	4.99	4.06	4.03
Total sales	**8.17**	7.45	7.77	6.84	6.25
Residential Average Annual Kilowatt-Hour Use Per Customer	**16,570**	14,716	15,162	15,696	15,663
Residential Average Annual Revenue Per Customer	**$1,853**	$1,597	$1,648	$1,525	$1,399
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,222**	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	**11,349**	10,701	10,747	10,144	10,309
Summer	**11,488**	10,870	11,518	12,211	11,744
Annual Load Factor (percent)	**62.6**	59.8	60.9	59.4	61.8
Plant Availability (percent):					
Fossil-steam	**92.9**	88.5	90.1	88.2	89.6
Nuclear	**88.4**	93.3	94.1	87.5	93.3
Source of Energy Supply (percent):					
Coal	**56.6**	53.4	58.5	60.9	60.2
Nuclear	**17.7**	18.6	17.8	16.5	17.4
Hydro	**5.0**	7.9	2.9	1.8	3.8
Gas	**14.0**	11.8	9.2	8.7	7.6
Purchased power -					
From non-affiliates	**1.6**	2.0	2.9	1.8	2.1
From affiliates	**5.1**	6.3	8.7	10.3	8.9
Total	**100.0**	100.0	100.0	100.0	100.0

[This page intentionally left blank]

GEORGIA POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2010 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2010.

W. Paul Bowers
President and Chief Executive Officer

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

February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the "Company") (a wholly owned subsidiary of 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. Our audits also included the financial statement schedule of the Company listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 II-211 to II-256) present fairly, in all material respects, the financial position of Georgia 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. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

Atlanta, Georgia
February 25, 2011

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of rising costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, and fuel prices. The Company is currently constructing two new nuclear and three new combined cycle generating units. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. On December 21, 2010, the Georgia Public Service Commission (PSC) approved an Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), including a base rate increase of approximately $562 million effective January 1, 2011. The Company is currently required to file its next fuel case by March 1, 2011.

Key Performance Indicators

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

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2010 fossil/hydro Peak Season EFOR of 1.89% 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 2010 performance was better than the target for these reliability measures.

Net income after dividends on preferred and preference stock is the primary measure of the Company's financial performance. The Company's 2010 results compared to 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 in customer surveys
Peak Season EFOR – fossil/hydro	5.06% or less	1.89%
Net Income after dividends on preferred and preference stock	$905 million	$950 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2010 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

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

The Company's 2009 net income after dividends on preferred and preference stock totaled $814 million representing an $89 million, or 9.8%, decrease from 2008. The decrease was primarily related to lower commercial and industrial base revenues resulting from the recessionary economy and decreased revenues from market-response rates to large commercial and industrial customers that were partially offset by cost containment activities, increased recognition of environmental compliance cost recovery revenues, and the amortization of the regulatory liability related to other cost of removal obligations.

The Company's 2008 net income after dividends on preferred and preference stock totaled $903 million representing a $67 million, or 8.0%, increase over 2007. The increase was primarily related to increased contributions from market-response rates for large commercial and industrial customers, higher retail base revenues resulting from the retail rate increase effective January 1, 2008 (2007 Retail Rate Plan), and increased allowance for equity funds used during construction. These increases were partially offset by increased depreciation and amortization resulting from more plant in service and changes to depreciation rates.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	**Increase (Decrease) from Prior Year**		
	2010	**2010**	2009	2008
		(in millions)		
Operating revenues	**$ 8,349**	**$ 657**	$(720)	$ 840
Fuel	**3,102**	**385**	(95)	171
Purchased power	**946**	**(33)**	(426)	355
Other operations and maintenance	**1,734**	**240**	(88)	21
Depreciation and amortization	**558**	**(97)**	18	126
Taxes other than income taxes	**344**	**27**	1	24
Total operating expenses	**6,684**	**522**	(590)	697
Operating income	**1,665**	**135**	(130)	143
Total other income and (expense)	**(245)**	**44**	(37)	5
Income taxes	**453**	**43**	(78)	70
Net income	**967**	**136**	(89)	78
Dividends on preferred and preference stock	**17**	**-**	-	11
Net income after dividends on preferred and preference stock	**$ 950**	**$ 136**	$ (89)	$ 67

Operating Revenues

Operating revenues in 2010, 2009, and 2008 and the percent of change from the prior year were as follows:

	Amount		
	2010	2009	2008
		(in millions)	
Retail – prior year	**$ 6,912**	$ 7,286	$ 6,498
Estimated change in –			
Rates and pricing	**-**	(64)	397
Sales growth (decline)	**48**	(92)	(22)
Weather	**207**	(6)	(37)
Fuel cost recovery	**441**	(212)	450
Retail – current year	**7,608**	6,912	7,286
Wholesale revenues –			
Non-affiliates	**380**	395	569
Affiliates	**53**	112	286
Total wholesale revenues	**433**	507	855
Other operating revenues	**308**	273	271
Total operating revenues	**$ 8,349**	$ 7,692	$ 8,412
Percent change	**8.5%**	(8.6)%	11.1%

Retail base revenues of $4.2 billion in 2010 increased by $255 million, or 6.5%, from 2009 primarily due to colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010. Residential base revenues increased $187 million, or 10.9%, commercial base revenues increased $50 million, or 3.1%, and industrial base revenues increased $17 million, or 3.1%. Revenues from changes in rates and pricing in 2010 were flat as the increased recognition of environmental compliance cost recovery revenues in accordance with the 2007 Retail Rate Plan were offset by pricing reductions from the structure of the Company's base rate tariffs. Retail base revenues of $3.9 billion in 2009 decreased by $162 million, or 3.9%, from 2008 primarily due to lower industrial and commercial base revenues resulting from the recessionary economy and decreased revenues from market-response rates to large commercial and industrial customers. Industrial base revenues decreased $207 million, or 27.9%, and commercial base revenues decreased $36 million, or 2.1%. These decreases were partially offset by an increase in residential base revenues of $78 million, or 4.8%. All customer classes were positively affected by increased recognition of environmental compliance cost recovery revenues. Retail base revenues of $4.1 billion in 2008 increased by $338 million, or 9.0%, from 2007 primarily due to an increase in revenues from market-response rates to large commercial and industrial customers, the retail rate increase effective January 1, 2008, and a 0.7% increase in retail customers. The increase was partially offset by a weak economy in the Southeast and less favorable weather in 2008 than in 2007. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

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

	2010	2009	2008
		(in millions)	
Unit power sales –			
Capacity	**$18**	$ 43	$ 40
Energy	**13**	26	44
Total	**31**	69	84
Other power sales –			
Capacity and other	**155**	140	129
Energy	**194**	186	356
Total	**349**	326	485
Total non-affiliated	**$380**	$395	$569

Wholesale revenues from sales to non-affiliates consist of power purchase agreements (PPA), unit power sales (UPS) contracts, and short-term opportunity sales. Wholesale revenues from PPAs and unit power sales contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy 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. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Revenues from unit power sales decreased $38 million, or 55.1%, in 2010 as a result of the UPS contract expiring on May 31, 2010. Revenues from unit power sales decreased $15 million, or 18.9%, in 2009 primarily due to a 26.0% decrease in kilowatt-hour (KWH) energy sales due to the recessionary economy and generally unfavorable weather. Revenues from unit power sales increased $18 million, or 27.4%, in 2008 driven by higher fuel costs and an 8.2% increase in the KWH sales primarily related to sales by the Company's generating units when other Southern Company system units were unavailable. Revenues from other non-affiliated sales increased $23 million, or 7.1%, in 2010, decreased $159 million, or 32.7%, in 2009, and increased $13 million, or 2.7%, in 2008. The increase in 2010 was primarily due to higher fuel costs and revenues from a PPA that replaced the expired UPS contract discussed previously. The decrease in 2009 was due to lower natural gas prices and a 49.7% decrease in KWH sales due to the recessionary economy and generally unfavorable weather. The increase in 2008 was primarily driven by higher fuel and purchased power costs, partially offset by a 9.8% decrease in KWH sales and lower emissions allowance prices.

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). In 2010, wholesale revenues from sales to affiliates decreased 52.7% due to a 60.1% decrease in KWH sales as a result of lower demand because the market cost of available energy was lower than the cost of the Company's available generation. In 2009, wholesale revenues from sales to affiliates decreased 60.9% due to lower natural gas prices and a 32.2% decrease in KWH sales due to the recessionary economy and generally unfavorable weather. In 2008, KWH sales to affiliated companies decreased 28.8% while revenues from sales to affiliates increased 3.0%. The revenue increase in 2008 was primarily due to the increased cost of fuel and other marginal generation components of the rates. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $35 million, or 12.8%, in 2010 primarily due to a $25 million increase in transmission revenues related to increased usage of the Company's transmission system by non-affiliated companies, an increase of $4 million in outdoor lighting revenues primarily as a result of new customer sales associated with government stimulus programs, and an increase of $6 million in late payment fees and customer maintenance request revenues. Other operating revenues remained relatively flat in 2009. Other operating revenues increased $13 million, or 4.8%, in 2008 primarily due to a $7 million increase in revenues from outdoor lighting and an $8 million increase in customer fees resulting from higher rates that went into effect in 2008, partially offset by a $2 million decrease in equipment rentals revenue.

Energy Sales

Changes in revenues are influenced heavily by the change in 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 billions)						
Residential	**29.4**	**12.0%**	(0.5)%	(1.6)%	**0.9%**	(0.5)%	(0.6)%
Commercial	**33.9**	**3.9**	(1.4)	0.0	**(0.4)**	(0.9)	1.2
Industrial	**23.2**	**6.4**	(9.7)	(5.2)	**5.1**	(9.5)	(4.8)
Other	**0.7**	**(1.2)**	0.1	(3.8)	**(1.9)**	0.4	(3.6)
Total retail	**87.2**	**7.1**	(3.5)	(2.1)	**1.5%**	(3.2)%	(1.2)%
Wholesale							
Non-affiliates	**4.6**	**(10.5)**	(46.6)	(7.8)			
Affiliates	**1.0**	**(60.1)**	(32.2)	(28.8)			
Total wholesale	**5.6**	**(26.6)**	(42.7)	(14.7)			
Total energy sales	**92.8**	**4.2%**	(8.9)%	(4.0)%			

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

In 2010, residential KWH sales increased 12.0%, commercial KWH sales increased 3.9%, and industrial KWH sales increased 6.4% compared to 2009 primarily due to colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010 and an improving economy.

Residential KWH sales decreased 0.5% in 2009 compared to 2008 primarily due to slightly less favorable weather, partially offset by an increase of 0.2% in residential customers. Commercial and industrial KWH sales decreased 1.4% and 9.7%, respectively, in 2009 compared to 2008 due to the recessionary economy. During 2009, there was a broad decline in demand across all industrial segments, most significantly in the chemical, primary metals, textiles, and stone, clay, and glass sectors.

Residential KWH sales decreased 1.6% in 2008 compared to 2007 primarily due to less favorable weather, partially offset by a 0.7% increase in residential customers. Commercial KWH sales remained flat in 2008 compared to 2007 despite a 0.2% increase in commercial customers. Industrial KWH sales decreased 5.2% in 2008 over 2007 primarily due to reduced demand and closures within the textile and primary and fabricated metal industries, which were a result of the slowing economy that worsened during the fourth quarter 2008.

See "Operating Revenues" above for a discussion of significant changes in sales to non-affiliates and sales to 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 *(billions of KWHs)*	**75.3**	72.4	80.8
Total purchased power *(billions of KWHs)*	**21.7**	20.4	21.3
Sources of generation *(percent)* -			
Coal	**67**	67	74
Nuclear	**21**	21	19
Gas	**10**	10	6
Hydro	**2**	2	1
Cost of fuel, generated *(cents per net KWH)* -			
Coal	**4.53**	4.12	3.44
Nuclear	**0.66**	0.55	0.51
Gas	**5.75**	5.30	6.90
Average cost of fuel, generated *(cents per net KWH)**	**3.82**	3.48	3.11
Average cost of purchased power *(cents per net KWH)*	**5.64**	6.06	8.10

*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.

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

Fuel and purchased power expenses were $3.7 billion in 2009, a decrease of $521 million, or 12.4%, below prior year costs. This decrease was due to a $371 million decrease related to fewer KWHs generated and purchased primarily due to lower customer demand as a result of the recessionary economy and a $150 million decrease in the average cost of purchased power, partially offset by an increase in the average cost of fuel.

Fuel and purchased power expenses were $4.2 billion in 2008, an increase of $526 million, or 14.3%, above prior year costs. Substantially all of this increase was due to the higher average cost of fuel and purchased power.

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. Uranium prices remained relatively constant during the early portion of 2010 but rose steadily during the second half of the year. At year end, uranium prices remained well below the highs set during 2007. Worldwide uranium production levels increased in 2010; however, secondary supplies and inventories were still required to meet worldwide reactor demand.

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

Other Operations and Maintenance Expenses

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

In 2009, other operations and maintenance expenses decreased $88 million, or 5.5%, compared to 2008. The decrease was due to a $46 million decrease in power generation, a $28 million decrease in transmission and distribution, and a $32 million decrease in customer accounting, service, and sales, most of which were related to cost containment activities in an effort to offset the effects of the recessionary economy.

In 2008, other operations and maintenance expenses increased $21 million, or 1.2%, compared to 2007. The increase was primarily the result of a $15 million increase in the accrual for property damage approved under the 2007 Retail Rate Plan, a $15 million increase in scheduled outages and maintenance for fossil generating plants, and a $22 million increase related to meter reading, records and collections, and uncollectible account expenses. These increases were partially offset by decreases of $25 million related to the timing of transmission and distribution operations and maintenance and $7 million related to medical, pension, and other employee benefits.

Depreciation and Amortization

Depreciation and amortization decreased $97 million, or 14.8%, in 2010 compared to the prior year. This decrease was primarily due to a $133 million increase in amortization of the regulatory liability related to other cost of removal obligations, as authorized by the Georgia PSC, partially offset by increased depreciation related to additional plant in service related to transmission, distribution, and environmental projects. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Rate Plans" herein, Note 1 to the financial statements under "Depreciation and Amortization," and Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

Depreciation and amortization increased $18 million, or 2.9%, in 2009 compared to the prior year primarily due to additional plant in service related to transmission, distribution, and environmental projects, partially offset by the amortization of $41 million of the regulatory liability related to other cost of removal obligations.

Depreciation and amortization increased $126 million, or 24.6%, in 2008 compared to the prior year primarily due to an increase in plant in service related to completed transmission, distribution, and environmental projects, changes in depreciation rates effective January 1, 2008 approved under the 2007 Retail Rate Plan, and the expiration of amortization related to a regulatory liability for purchased power costs under the terms of the retail rate plan for the three years ended December 31, 2007.

Taxes Other Than Income Taxes

In 2010, taxes other than income taxes increased $27 million, or 8.5%, from the prior year primarily due to higher municipal franchise fees resulting from retail revenue increases during 2010. In 2009, the increase in taxes other than income taxes was immaterial. In 2008, taxes other than income taxes increased $24 million, or 8.6%, from the prior year primarily due to higher municipal franchise fees resulting from retail revenue increases during 2008.

Allowance for Funds Used During Construction Equity

Allowance for funds used during construction (AFUDC) equity increased $50 million, or 51.5%, in 2010 primarily due to the increase in construction related to three new combined cycle units at Plant McDonough, two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4), and ongoing environmental and transmission projects. In 2009, the increase in AFUDC equity as compared to 2008 was immaterial. AFUDC equity increased $27 million, or 39.8%, in 2008 primarily due to the increase in construction related to ongoing environmental and transmission projects, as well as the new units at Plant McDonough. See FUTURE EARNINGS POTENTIAL – "Construction" herein and Note 3 to the financial statements under "Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2010, interest expense, net of amounts capitalized decreased $11 million, or 2.8%, primarily due to a $14 million increase in interest capitalized in 2010 compared to the prior year. In 2009, interest expense, net of amounts capitalized increased $41 million, or 11.7%, primarily due to an increase in long-term debt levels resulting from the issuance of additional senior notes and pollution control bonds to fund the Company's ongoing construction program. The increase in interest expense in 2008 as compared to 2007 was immaterial.

Other Income (Expense), Net

Other income (expense), net decreased $20 million in 2010 primarily as a result of lower revenues of $9 million from non-operating activities and increased donations of $5 million. Other income (expense), net increased $7 million, or 80.8%, in 2009 primarily related to $2 million and $1 million increases in customer contracting and income resulting from purchases by large commercial and industrial customers of hedges against market-response rates, respectively, and a decrease of $2 million in donations. Other income (expense), net decreased $23 million, or 163.0%, in 2008 primarily due to a $13 million change in classification of revenues related to a residential pricing program to base retail revenues in 2008 as ordered by the Georgia PSC under the 2007 Retail Rate Plan, as well as decreased revenues of $7 million and $3 million related to non-operating rental income and customer contracting, respectively.

Income Taxes

Income taxes increased $43 million, or 10.5%, in 2010 primarily due to higher pre-tax earnings, partially offset by increases in non-taxable AFUDC equity and state tax credits. Income taxes decreased $78 million, or 15.9%, in 2009 primarily due to changes in pre-tax income. Income taxes increased $70 million, or 16.8%, in 2008 primarily due to increased pre-tax net income and the effect of deductions for the Company's donation of 2,200 acres in the Tallulah Gorge area to the State of Georgia in 2007. This increase was partially offset by an increase in AFUDC equity, as well as additional state tax credits and an increase in the federal production activities deduction.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

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

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

Environmental Matters

Compliance costs related to 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. The Company's environmental compliance cost recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations.

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 the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The action was filed concurrently with the issuance of a notice of violation of the NSR provisions to the Company. 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 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 the Company, 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 now be determined.

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 $3.7 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $217 million, $440 million, and $689 million for 2010, 2009, and 2008, respectively. The Company expects that capital expenditures to comply with existing statutes and regulations will be $73 million, $79 million, and $58 million in 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 could range from $69 million to $289 million in 2011, $191 million to $651 million in 2012, and $476 million to $1.4 billion 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.

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 $3.4 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned and others are 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. A 20-county area within metropolitan Atlanta is the only location within the Company's service area that is currently designated as nonattainment for the current standard. On November 30, 2010, the EPA extended the attainment date for this area by one year as a result of improving air quality. 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 Company's service area. State implementation plans demonstrating attainment with annual standards 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 Georgia and Alabama, 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 Georgia and Alabama have completed their 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 Georgia and Alabama, 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 Georgia and Alabama, 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 any of the Company's facilities. The State of Georgia is currently completing its implementation plan 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.

On April 29, 2010, the EPA issued a proposed Industrial Boiler (IB) MACT rule that would establish emissions limits for various hazardous air pollutants typically emitted from industrial boilers, including biomass boilers and start-up boilers. The EPA issued the final rules on February 23, 2011 and, at the same time, issued a notice of intent to reconsider the final rules to allow for additional public review and comment. The impact of these regulations will depend on their final form and the outcome of any legal challenges and cannot be determined at this time.

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 rules for electric generating units and industrial boilers 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 has already installed a number of SO_2 and NO_x emissions controls to ensure continued compliance with applicable air quality requirements.

In addition to the federal air quality laws described above, the Company also is subject to the requirements of the State of Georgia's Multi-Pollutant Rule, which was adopted in 2007. The Multi-Pollutant Rule is designed to reduce emissions of mercury, SO_2, and NO_x state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and June 1, 2015. The State of Georgia also adopted a companion rule that requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2010, the Company had installed the required controls on 10 of its largest coal-fired generating units and is in the process of installing the required controls on six additional units. As a result of uncertainties related to the potential federal air quality regulations described above, the Company has suspended certain work related to both the installation of emissions control equipment at Plant Branch Units 1 and 2 and Plant Yates Units 6 and 7 and the conversion of Plant Mitchell from coal-fired to biomass-fired. The Company continues to analyze the potential costs and benefits of installing the required controls on its remaining coal-fired generating units in light of the potential federal regulations described above. The Company may determine that retiring and replacing certain of these existing units with new generating resources or purchased power is more economically efficient than installing the required environmental controls.

The Company currently expects to file an update to its integrated resource plan in June 2011. Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets (resulting from new or revised environmental regulations) through 2013 that are approved by the Georgia PSC in connection with an updated integrated resource plan will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. Such costs that may be deferred as a regulatory asset include any impairment losses that may result from a decision to retire certain units that are no longer cost effective in light of new or modified environmental regulations. In addition, in connection with the 2010 ARP, the Georgia PSC also approved revised depreciation rates that will recover the remaining book value of certain of the Company's existing coal-fired units by December 31, 2014.

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

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 of the Company's 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.

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. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Coal Combustion Byproducts

The Company currently operates 11 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 also sells a portion of its coal combustion byproducts to third parties for beneficial reuse (approximately one-fourth in recent years). Historically, individual states have regulated coal combustion byproducts and the states in Southern Company's service territory, including the States of Georgia and Alabama, 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, natural gas, and biomass 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 48 million metric tons. The preliminary estimate of carbon dioxide emissions from these units in 2010 is approximately 51 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 is actively constructing new generating facilities with lower greenhouse gas emissions. These include Plant Vogtle Units 3 and 4 and three combined cycle units at Plant McDonough. The Company has also proposed the conversion of Plant Mitchell from coal-fired to biomass generation and is currently evaluating the costs and viability of other renewable technologies for the State of Georgia. On February 2, 2010, the Georgia PSC approved the Company's request to delay construction activities related to Plant Mitchell pending the EPA's anticipated issuance of regulations associated with coal combustion byproducts and the IB MACT rule described previously.

PSC Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 under the 2007 Retail Rate Plan. In June 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of filing to increase customer rates as allowed under the 2007 Retail Rate Plan, in June 2009, the Company filed a request with the Georgia PSC for an accounting order that would allow the Company to amortize up to $324 million of its regulatory liability related to other cost of removal obligations.

In August 2009, the Georgia PSC approved the accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million of the regulatory liability, respectively.

On December 21, 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff (PSC Staff), and eight other intervenors. Under the terms of the 2010 ARP, the Company will amortize approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

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

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

- Effective January 1, 2012, the DSM tariffs will increase by $17 million;
- Effective April 1, 2012, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4 and 5 for the period from commercial operation through December 31, 2013;
- Effective January 1, 2013, the DSM tariffs will increase by $18 million;
- Effective January 1, 2013, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Unit 6 for the period from commercial operation through December 31, 2013; and
- The MFF tariff will increase consistent with these adjustments.

The Company currently estimates these adjustments will result in annualized base revenue increases of approximately $190 million in 2012 and $93 million in 2013.

Under the 2010 ARP, the Company's retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25 % will be directly refunded to customers, with the remaining one-third retained by the Company. If at any time during the term of the 2010 ARP, the Company projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust the Company's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, the Company may file a full rate case.

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

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved increases in the Company's total annual billings of approximately $222 million effective June 1, 2008 and $373 million effective April 1, 2010. In addition, the Georgia PSC has authorized an interim fuel rider, which would allow the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered balance exceeds budget by more than $75 million. The Company is currently required to file its next fuel case by March 1, 2011.

The Company's under recovered fuel balance totaled approximately $398 million of which approximately $214 million is included in deferred charges and other assets in the balance sheets at December 31, 2010.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, a change in the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Legislation

Stimulus Funding

On April 28, 2010, Southern Company signed a Smart Grid Investment Grant agreement with the U.S. Department of Energy (DOE), 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, $51 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, the Company deferred the related impact as a regulatory asset, which is being amortized over 12 years, in accordance with the 2010 ARP, and therefore 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

Georgia State Income Tax Credits

The Company's 2005 through 2009 income tax filings for the State of Georgia include state income tax credits for increased activity through Georgia ports. The Company filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue (DOR) has not responded to these claims. In July 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On March 22, 2010, the Superior Court of Fulton County ruled in favor of the Company's motion for summary judgment. The Georgia DOR has appealed to the Georgia Court of Appeals and a decision is expected later this year. Any decision may be subject to further appeal to the Georgia Supreme Court. An unrecognized tax benefit has been recorded related to these credits. If the Company prevails, no material impact on the Company's net income is expected as a significant portion of any tax benefit is expected to be returned to retail customers in accordance with the 2010 ARP. If the Company is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on the Company's cash flow. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot now be determined.

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 $133 million for the Company. Although Internal Revenue Service (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 $168 million in increased cash flow. The Company estimates the potential increased cash flow for 2011 to be between approximately $275 million and $350 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.

Construction

Nuclear

In August 2009, the Nuclear Regulatory Commission (NRC) issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of the Company, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), related to Plant Vogtle Units 3 and 4. See Note 4 to the financial statements for additional information on these co-owners. In March 2008, Southern Nuclear filed an application with the NRC for a combined construction and operating license (COL) for the new units. If licensed by the NRC, Plant Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively.

In April 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COL or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In March 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve the inclusion of the related construction work in progress accounts in rate base. In April 2009 the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows the Company to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allows the Company to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion.

The Georgia PSC has ordered the Company to report against this total certified cost of approximately $6.1 billion. In addition, on December 21, 2010, the Georgia PSC approved the Company's Nuclear Construction Cost Recovery (NCCR) tariff. The NCCR tariff became effective January 1, 2011 and is expected to collect approximately $223 million in revenues during 2011.

On February 21, 2011, the Georgia PSC voted to approve the Company's third semi-annual construction monitoring report including total costs of $1.048 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2010. In connection with its certification of Vogtle Units 3 and 4, the Georgia PSC ordered the Company and the PSC Staff to work together to develop a risk sharing or incentive mechanism that would provide some level of protection to ratepayers in the event of significant cost overruns, but also not penalize the Company's earnings if and when overruns are due to mandates from governing agencies. Such discussions have continued through the third semi-annual construction monitoring proceedings; however, the Georgia PSC has deferred a decision with respect to any related incentive or risk-sharing mechanism until a later date. The Company will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In 2009, the Southern Alliance for Clean Energy (SACE) and the Fulton County Taxpayers Foundation, Inc. (FCTF) filed separate petitions in the Superior Court of Fulton County, Georgia seeking review of the Georgia PSC's certification order and challenging the constitutionality of the Georgia Nuclear Energy Financing Act. On May 5, 2010, the court dismissed as premature the plaintiffs' claim challenging the Georgia Nuclear Energy Financing Act. FCTF appealed the decision, and the Georgia Supreme Court ruled against FCTF, finding the suit premature. In addition, on May 5, 2010, the Superior Court of Fulton County issued an order remanding the Georgia PSC's certification order for inclusion of further findings of fact and conclusions of law by the Georgia PSC. In compliance with the court's order, the Georgia PSC issued its order on remand to include further findings of fact and conclusions of law on June 23, 2010. On July 5, 2010, SACE and FCTF filed separate motions with the Georgia PSC for reconsideration of the order on remand. On August 17, 2010, the Georgia PSC voted to reaffirm its order. The matter is no longer subject to judicial review and is now concluded.

On December 2, 2010, Westinghouse submitted an AP1000 Design Certification Amendment (DCA) to the NRC. On February 10, 2011, the NRC announced that it was seeking public comment on a proposed rule to approve the DCA and amend the certified AP1000 reactor design for use in the U.S. The Advisory Committee on Reactor Safeguards also issued a letter on January 24, 2011 endorsing the issuance of the COL for Plant Vogtle Units 3 and 4. The Company currently expects to receive the COL for Plant Vogtle Units 3 and 4 from the NRC in late 2011 based on the NRC's February 16, 2011 release of its COL schedule framework.

There are other pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4. Similar additional challenges at the state and federal level are expected as construction proceeds.

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

Other Construction

On May 6, 2010, the Georgia PSC approved the Company's request to extend the construction schedule for Plant McDonough Units 4, 5, and 6 as a result of the short-term reduction in forecasted demand, as well as the requested increase in the certified amount. As a result, the units are expected to be placed into service in January 2012, May 2012, and January 2013, respectively. To date, the Georgia PSC has approved the Company's quarterly construction monitoring reports, including actual project expenditures incurred, through June 30, 2010. The Company will continue to file quarterly construction monitoring reports throughout the construction period.

Other Matters

The Company is involved in various other matters being litigated, regulatory matters, and certain tax-related issues 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 Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations 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 Georgia DOR 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, the Georgia DOR, 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 $9 million or less change in total benefit expense and a $112 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 and the nuclear decommissioning trust funds remained stable in value as of December 31, 2010. In December 2010, the Company contributed $168 million to the qualified pension plan. The Company will fund approximately $3 million, $2 million, and $2 million to its nuclear decommissioning trust funds in 2011, 2012, and 2013, respectively.

Net cash provided from operating activities totaled $1.8 billion in 2010, an increase of $429 million from 2009, primarily due to a $136 million increase in net income, fuel inventory reductions in 2010 compared to additions in 2009, and a net increase of $94 million in deferred and prepaid income taxes primarily due to the extension of bonus depreciation and the change in the tax accounting method for repair costs (See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Tax Method of Accounting For Repairs" and "Bonus Depreciation" herein), partially offset by the contributions to the qualified pension plan. Net cash provided from operating activities totaled $1.4 billion in 2009, a decrease of $310 million from 2008, primarily due to an $89 million decrease in net income, a reduction in deferred revenues of approximately $172 million, a reduction in accrued compensation of approximately $123 million, and an increase in fuel inventory additions of approximately $150 million, partially offset by a reduction in accounts receivable of approximately $210 million. Net cash provided from operating activities totaled $1.7 billion in 2008, an increase of

$279 million from 2007, primarily due to higher retail operating revenues partially offset by higher inventory additions.

Net cash used for investing activities totaled $2.2 billion, $2.4 billion, and $1.9 billion in 2010, 2009, and 2008, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities; and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years have been provided from operating activities, capital contributions from Southern Company, and the issuance of debt.

Net cash provided from financing activities totaled $391 million, $881 million, and $310 million for 2010, 2009, and 2008, respectively. These totals are primarily related to additional issuances of senior notes and capital contributions from Southern Company in all years. The statements of cash flows provide additional details. See "Financing Activities" herein.

Significant balance sheet changes in 2010 include a $1.6 billion increase in total property, plant, and equipment related to the construction activities discussed above. Other significant balance sheet changes in 2010 include an increase in paid-in capital of $698 million reflecting equity contributions from Southern Company. Significant balance sheet changes in 2009 include a $1.9 billion increase in total property, plant, and equipment and a $776 million increase in long-term debt to provide funds for the Company's continuous construction program.

The Company's ratio of common equity to total capitalization, including short-term debt, was 48.8% in 2010 and 47.8% in 2009. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described below with respect to potential DOE loan guarantees, the Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend on prevailing market conditions, regulatory approvals, and other factors.

On June 18, 2010, the Company reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future borrowings by the Company related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to the Company and secured by a first priority lien on the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs or approximately $3.4 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to receipt of the COL for Plant Vogtle Units 3 and 4 from the NRC, negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. There can be no assurance that the DOE will issue loan guarantees for the Company. See FUTURE EARNINGS POTENTIAL – "Construction – Nuclear" herein and Note 3 to the financial statements under "Construction – Nuclear" for more information on Plant Vogtle Units 3 and 4.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC 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 for under recovered fuel costs and to meet cash needs which can fluctuate significantly due to the seasonality of the business.

To meet short-term cash needs and contingencies, at December 31, 2010 the Company had credit arrangements with banks totaling $1.7 billion. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. In addition, the Company has substantial cash flow from operating activities and access to capital markets, including a commercial paper program, to meet liquidity needs.

At December 31, 2010, bank credit arrangements were as follows:

		Expires	
Total	Unused	2011	2012
	(in millions)		
$1,715	$1,703	$595	$1,120

Of the credit arrangements that expire in 2011, $40 million allow for the execution of term loans for an additional two-year period, and $220 million allow for execution of term loans for a one-year period. 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 $385 million outstanding pollution control revenue bonds requiring liquidity support. Subsequent to December 31, 2010, the Company's remarketing of $137 million of variable rate pollution control revenue bonds increased the total requiring liquidity support to $522 million.

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 issuances for the benefit of any other operating company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support. As of December 31, 2010, the Company had $575 million of outstanding commercial paper.

During 2010, the maximum amount of commercial paper outstanding was $575 million and the average amount outstanding was $167 million. During 2009, the maximum amount of commercial paper outstanding was $757 million and the average amount outstanding was $348 million. The weighted average annual interest rate on commercial paper in 2010 and 2009 was 0.3% and 0.4%, respectively. 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 March 2010, the Company issued $350 million aggregate principal amount of Series 2010A Floating Rate Senior Notes due March 15, 2013. The net proceeds were used to repay at maturity $250 million aggregate principal amount of Series 2008A Floating Rate Senior Notes due March 17, 2010, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In June 2010, the Company issued $600 million aggregate principal amount of Series 2010B 5.40% Senior Notes due June 1, 2040. The net proceeds from the sale of the Series 2010B Senior Notes were used for the redemption of all of the $200 million aggregate principal amount of the Company's Series R 6.00% Senior Notes due October 15, 2033 and all of the $150 million aggregate principal amount of the Company's Series O 5.90% Senior Notes due April 15, 2033, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In September 2010, the Company issued $500 million aggregate principal amount Series 2010C 4.75% Senior Notes due September 1, 2040. The net proceeds were used to redeem all of the $250 million aggregate principal amount of the Company's Series X 5.70% Senior Notes due January 15, 2045, $125 million aggregate principal amount of the Company's Series W 6.00% Senior Notes due August 15, 2044, $100 million aggregate principal amount of the Company's Series T 5.75% Senior Public Income Notes due January 15, 2044, and $35 million aggregate principal amount of the Company's Series G 5.75% Senior Notes due December 1, 2044.

Also in September 2010, the Company issued $500 million aggregate principal amount Series 2010D 1.30% Senior Notes due September 15, 2013. The net proceeds were used for the repurchase of all of the $114 million aggregate principal amount of outstanding Development Authority of Burke County Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2009, due January 1, 2049; $40 million aggregate principal amount of the outstanding Development Authority of Monroe County Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2009, due January 1, 2049; $173 million aggregate principal amount of the outstanding Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2009, due December 1, 2032; $89 million aggregate principal amount of the outstanding Development Authority of Monroe County Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), Second Series 2009, due October 1, 2048; and $46 million aggregate principal amount of the outstanding Development Authority of Burke County Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 1996, due October 1, 2032, and for other general corporate purposes, including the Company's continuous construction program. The pollution control revenue bonds repurchased by the Company are being held by the Company and may be remarketed to investors in the future.

In December 2010, the Development Authority of Floyd County issued $53 million aggregate principal amount Pollution Control Revenue Bonds (Georgia Power Company Plant Hammond Project), First Series 2010 (the 2010 Bonds) for the benefit of the Company, and the 2010 Bonds were purchased by the Company. The proceeds from the issuance of the 2010 Bonds were used in December 2010 to purchase and cancel the $53 million aggregate principal amount Development Authority of Floyd County Pollution Control Revenue Bonds (Georgia Power Company Plant Hammond Project), First Series 2008. In January 2011, the Company remarketed the 2010 Bonds to investors.

Also subsequent to December 31, 2010, the Company issued $300 million aggregate principal amount of Series 2011A Floating Rate Senior Notes due January 15, 2013. The proceeds were used to repay a portion of the Company's outstanding short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

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

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, and construction of new generation. At December 31, 2010, the maximum potential collateral requirements under these contracts at a BBB- and/or Baa3 rating were approximately $27 million. At December 31, 2010, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $1.4 billion. 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 also downgraded the trust preferred securities rating of the Company to Baa1 from A3. Moody's also announced that the ratings outlook for the Company is stable.

On December 22, 2010, Fitch Ratings, Inc. announced that the ratings outlook of the Company had been revised from negative to 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 rate 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 tests, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $1.0 billion of outstanding variable rate long-term debt at January 1, 2011 was 0.57%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $10 million at January 1, 2011. For further information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 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 fuel hedging program implemented per the guidelines of the Georgia 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 millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (75)**	$ (113)
Contracts realized or settled	**85**	150
Current period changes[(a)]	**(110)**	(112)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (100)**	$ (75)

(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 a decrease of $25 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 58.7 million mmBtu with a weighted average contract cost approximately $1.74 per mmBtu above market prices, and 64.6 million mmBtu at December 31, 2009 with a weighted average contract cost approximately $1.16 per mmBtu above market prices. All natural gas hedges gains and losses are recovered through the Company's fuel cost recovery mechanism.

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 mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are actively quoted, and thus fall into Level 2. See Note 10 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 millions)		
Level 1	$ -	$ -	$ -	$ -
Level 2	(100)	(77)	(23)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$ (100)	$ (77)	$ (23)	$ -

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

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

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to include a base level investment of $2.1 billion, $2.2 billion, and $2.0 billion for 2011, 2012, and 2013, respectively. Included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $73 million, $79 million, and $58 million for 2011, 2012, and 2013, respectively. In addition, the Company currently estimates that potential incremental investments to comply with anticipated new environmental regulations could range from $69 million to $289 million in 2011, $191 million to $651 million in 2012, and $476 million to $1.4 billion in 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; 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; Georgia PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 and Note 7 to the financial statements under "Construction – Nuclear" and "Construction Program," respectively, for additional information.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

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

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2011	2012-2013	2014-2015	After 2015	Uncertain Timing [d]	Total
			(in millions)			
Long-term debt[a] –						
Principal	$ 411	$ 1,575	$ 250	$ 6,069	$ -	$ 8,305
Interest	378	731	642	5,846	-	7,597
Preferred and preference stock dividends[b]	17	35	35	-	-	87
Energy-related derivative obligations[c]	77	24	-	-	-	101
Operating leases	36	37	22	8	-	103
Capital leases	4	9	11	35	-	59
Unrecognized tax benefits and interest[d]	203	-	-	-	61	264
Purchase commitments[e] –						
Capital[f]	1,858	3,878	-	-	-	5,736
Limestone [g]	17	36	30	10	-	93
Coal	1,869	1,538	786	1,182	-	5,375
Nuclear fuel	252	333	263	585	-	1,433
Natural gas[h]	445	984	769	2,665	-	4,863
Purchased power	316	509	464	1,726	-	3,015
Long-term service agreements[i]	18	102	111	467	-	698
Trusts –						
Nuclear decommissioning[j]	3	4	4	35	-	46
Pension and other postretirement benefit plans[k]	22	52	-	-	-	74
Total	$ 5,926	$ 9,847	$3,387	$ 18,628	$ 61	$ 37,849

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

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

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

(d) The timing related to the realization of $61 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. Of the total $264 million, $144 million is the estimated cash payment. See Note 3 under "Income Tax Matters" and Note 5 under "Unrecognized Tax Benefits" to the financial statements for additional information.

(e) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2010, 2009, and 2008 were $1.7 billion, $1.5 billion, and $1.6 billion, respectively.

(f) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel. In addition, such amounts exclude the Company's estimates of potential incremental investments to comply with anticipated new environmental regulations which could range from $69 million to $289 million in 2011, $191 million to $651 million in 2012, and $476 million to $1.4 billion in 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) Long-term service agreements include price escalation based on inflation indices.

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

(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, customer growth, economic recovery, fuel cost recovery and other rate actions, environmental regulations and expenditures, the Company's projections for qualified pension plan, other postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, impacts 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, start and completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality, coal combustion byproducts, and emissions of sulfur, nitrogen, mercury, 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 pending EPA civil action 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, business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to the Plant Vogtle expansion, including Georgia PSC and NRC approvals and potential DOE loan guarantees;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- 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

[This page intentionally left blank]

STATEMENTS OF INCOME

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

Georgia Power Company 2010 Annual Report

	2010	2009	2008
		(in millions)	
Operating Revenues:			
Retail revenues	**$7,608**	$6,912	$7,286
Wholesale revenues, non-affiliates	**380**	395	569
Wholesale revenues, affiliates	**53**	112	286
Other revenues	**308**	273	271
Total operating revenues	**8,349**	7,692	8,412
Operating Expenses:			
Fuel	**3,102**	2,717	2,812
Purchased power, non-affiliates	**368**	269	443
Purchased power, affiliates	**578**	710	962
Other operations and maintenance	**1,734**	1,494	1,582
Depreciation and amortization	**558**	655	637
Taxes other than income taxes	**344**	317	316
Total operating expenses	**6,684**	6,162	6,752
Operating Income	**1,665**	1,530	1,660
Other Income and (Expense):			
Allowance for equity funds used during construction	**147**	97	95
Interest income	**5**	2	7
Interest expense, net of amounts capitalized	**(375)**	(386)	(345)
Other income (expense), net	**(22)**	(2)	(9)
Total other income and (expense)	**(245)**	(289)	(252)
Earnings Before Income Taxes	**1,420**	1,241	1,408
Income taxes	**453**	410	488
Net Income	**967**	831	920
Dividends on Preferred and Preference Stock	**17**	17	17
Net Income After Dividends on Preferred and Preference Stock	**$ 950**	$ 814	$ 903

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

Georgia Power Company 2010 Annual Report

	2010	2009	2008
		(in millions)	
Operating Activities:			
Net income	**$ 967**	$ 831	$ 920
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**724**	791	758
Deferred income taxes	**342**	191	171
Deferred revenues	**(101)**	(49)	123
Deferred expenses	**(13)**	(4)	2
Allowance for equity funds used during construction	**(147)**	(97)	(95)
Pension, postretirement, and other employee benefits	**21**	2	19
Pension and postretirement funding	**(195)**	(22)	(22)
Hedge settlements	**-**	(19)	(23)
Insurance cash surrender value	**1**	20	-
Other, net	**20**	24	2
Changes in certain current assets and liabilities --			
-Receivables	**168**	127	(83)
-Fossil fuel stock	**103**	(242)	(92)
-Materials and supplies	**(7)**	(6)	(20)
-Prepaid income taxes	**(36)**	21	(15)
-Other current assets	**(2)**	(1)	(18)
-Accounts payable	**(99)**	(54)	(56)
-Accrued taxes	**31**	(19)	118
-Accrued compensation	**62**	(101)	22
-Other current liabilities	**8**	25	17
Net cash provided from operating activities	**1,847**	1,418	1,728
Investing Activities:			
Property additions	**(2,190)**	(2,515)	(1,848)
Distribution of restricted cash from pollution control revenue bonds	**-**	27	33
Nuclear decommissioning trust fund purchases	**(1,772)**	(989)	(419)
Nuclear decommissioning trust fund sales	**1,768**	984	412
Cost of removal, net of salvage	**(67)**	(56)	(63)
Change in construction payables, net of joint owner portion	**36**	106	3
Other investing activities	**(19)**	25	(38)
Net cash used for investing activities	**(2,244)**	(2,418)	(1,920)
Financing Activities:			
Increase (decrease) in notes payable, net	**252**	(33)	(358)
Proceeds --			
Capital contributions from parent company	**688**	931	273
Pollution control revenue bonds issuances	**-**	417	386
Senior notes issuances	**1,950**	1,000	1,000
Other long-term debt issuances	**-**	1	301
Redemptions --			
Pollution control revenue bonds	**(516)**	(327)	(336)
Capital leases	**(3)**	(2)	(1)
Senior notes	**(1,112)**	(333)	(198)
Payment of preferred and preference stock dividends	**(18)**	(18)	(17)
Payment of common stock dividends	**(820)**	(739)	(721)
Other financing activities	**(30)**	(16)	(19)
Net cash provided from financing activities	**391**	881	310
Net Change in Cash and Cash Equivalents	**(6)**	(119)	118
Cash and Cash Equivalents at Beginning of Year	**14**	133	15
Cash and Cash Equivalents at End of Year	**$ 8**	$ 14	$ 133
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $54, $40 and $40 capitalized, respectively)	**$339**	$341	$309
Income taxes (net of refunds)	**149**	228	280

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

BALANCE SHEETS

At December 31, 2010 and 2009

Georgia Power Company 2010 Annual Report

Assets	**2010**	2009
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 8**	$ 14
Receivables --		
Customer accounts receivable	**580**	487
Unbilled revenues	**172**	172
Under recovered regulatory clause revenues	**184**	292
Joint owner accounts receivable	**60**	147
Other accounts and notes receivable	**67**	63
Affiliated companies	**21**	12
Accumulated provision for uncollectible accounts	**(11)**	(10)
Fossil fuel stock, at average cost	**624**	726
Materials and supplies, at average cost	**371**	363
Vacation pay	**78**	75
Prepaid income taxes	**99**	133
Other regulatory assets, current	**105**	77
Other current assets	**80**	61
Total current assets	**2,438**	2,612
Property, Plant, and Equipment:		
In service	**26,397**	25,120
Less accumulated provision for depreciation	**9,966**	9,493
Plant in service, net of depreciation	**16,431**	15,627
Nuclear fuel, at amortized cost	**386**	340
Construction work in progress	**3,287**	2,521
Total property, plant, and equipment	**20,104**	18,488
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**70**	66
Nuclear decommissioning trusts, at fair value	**818**	580
Miscellaneous property and investments	**42**	39
Total other property and investments	**930**	685
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**723**	609
Prepaid pension costs	**91**	-
Deferred under recovered regulatory clause revenues	**214**	373
Other regulatory assets, deferred	**1,207**	1,322
Other deferred charges and assets	**207**	206
Total deferred charges and other assets	**2,442**	2,510
Total Assets	**$25,914**	$24,295

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

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

Liabilities and Stockholder's Equity	**2010**	2009
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 415**	$ 254
Notes payable	**576**	324
Accounts payable --		
Affiliated	**243**	239
Other	**574**	602
Customer deposits	**198**	200
Accrued taxes --		
Unrecognized tax benefits	**187**	165
Other accrued taxes	**328**	291
Accrued interest	**94**	89
Accrued vacation pay	**58**	58
Accrued compensation	**109**	43
Liabilities from risk management activities	**77**	50
Other cost of removal obligations, current	**31**	216
Other regulatory liabilities, current	**1**	100
Nuclear decommissioning trust securities lending collateral	**144**	14
Other current liabilities	**134**	69
Total current liabilities	**3,169**	2,714
Long-Term Debt (See accompanying statements)	**7,931**	7,782
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,718**	3,390
Deferred credits related to income taxes	**129**	134
Accumulated deferred investment tax credits	**229**	242
Employee benefit obligations	**684**	923
Asset retirement obligations	**705**	677
Other cost of removal obligations	**131**	125
Other deferred credits and liabilities	**211**	139
Total deferred credits and other liabilities	**5,807**	5,630
Total Liabilities	**16,907**	16,126
Preferred Stock (See accompanying statements)	**45**	45
Preference Stock (See accompanying statements)	**221**	221
Common Stockholder's Equity (See accompanying statements)	**8,741**	7,903
Total Liabilities and Stockholder's Equity	**$25,914**	$24,295
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
Georgia Power Company 2010 Annual Report

	2010	2009	2010	2009
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts --				
5.88% due 2044	**$ 206**	$ 206		
Long-term notes payable --				
Variable rate (0.80% at 1/1/10) due 2010	**-**	250		
Variable rate (0.78% at 1/1/11) due 2011	**300**	300		
Variable rate (0.62% at 1/1/11) due 2013	**350**	-		
4.00% to 5.57% due 2011	**103**	103		
5.125% due 2012	**200**	200		
1.30% to 6.00% due 2013	**1,025**	525		
5.25% due 2015	**250**	250		
4.25% to 8.20% due 2017-2048	**4,351**	4,113		
Total long-term notes payable	**6,579**	5,741		
Other long-term debt --				
Pollution control revenue bonds:				
0.80% to 5.75% due 2016-2048	**1,134**	1,134		
Variable rate (0.39% at 1/1/11) due 2011	**8**	8		
Variable rate (0.33% to 0.46% at 1/1/11) due 2016-2041	**377**	893		
Total other long-term debt	**1,519**	2,035		
Capitalized lease obligations	**59**	63		
Unamortized debt discount	**(17)**	(9)		
Total long-term debt (annual interest requirement -- $377.7 million)	**8,346**	8,036		
Less amount due within one year	**415**	254		
Long-term debt excluding amount due within one year	**7,931**	7,782	**46.8%**	48.8%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value -- 6.125%				
Authorized - 50,000,000 shares				
Outstanding - 1,800,000 shares	**45**	45		
Non-cumulative preference stock				
$100 par value -- 6.50%				
Authorized - 15,000,000 shares				
Outstanding - 2,250,000 shares	**221**	221		
Total preferred and preference stock (annual dividend requirement -- $17.4 million)	**266**	266	**1.6**	1.7
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized: 20,000,000 shares				
Outstanding: 9,261,500 shares	**398**	398		
Paid-in capital	**5,291**	4,593		
Retained earnings	**3,063**	2,933		
Accumulated other comprehensive income (loss)	**(11)**	(21)		
Total common stockholder's equity	**8,741**	7,903	**51.6**	49.5
Total Capitalization	**$16,938**	$15,951	**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

Georgia Power Company 2010 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in millions)			
Balance at December 31, 2007	9	$398	$3,375	$2,676	$(14)	$6,435
Net income after dividends on preferred and preference stock	-	-	-	903	-	903
Capital contributions from parent company	-	-	281	-	-	281
Other comprehensive loss	-	-	-	-	(19)	(19)
Cash dividends on common stock	-	-	-	(721)	-	(721)
Balance at December 31, 2008	9	398	3,656	2,858	(33)	6,879
Net income after dividends on preferred and preference stock	-	-	-	814	-	814
Capital contributions from parent company	-	-	937	-	-	937
Other comprehensive income	-	-	-	-	12	12
Cash dividends on common stock	-	-	-	(739)	-	(739)
Balance at December 31, 2009	**9**	**398**	**4,593**	**2,933**	**(21)**	**7,903**
Net income after dividends on preferred and preference stock	**-**	**-**	**-**	**950**	**-**	**950**
Capital contributions from parent company	**-**	**-**	**698**	**-**	**-**	**698**
Other comprehensive income	**-**	**-**	**-**	**-**	**10**	**10**
Cash dividends on common stock	**-**	**-**	**-**	**(820)**	**-**	**(820)**
Balance at December 31, 2010	**9**	**$ 398**	**$ 5,291**	**$ 3,063**	**$(11)**	**$ 8,741**

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

Georgia Power Company 2010 Annual Report

	2010	2009	2008
		(in millions)	
Net income after dividends on preferred and preference stock	**$950**	$814	$903
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(1), and $(13), respectively	**-**	(2)	(21)
Reclassification adjustment for amounts included in net income, net of tax of $6, $9, and $1, respectively	**10**	14	2
Total other comprehensive income (loss)	**10**	12	(19)
Comprehensive Income	**$960**	$826	$884

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power Company (Alabama Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets 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 and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants, including the Company's Plants Hatch and Vogtle.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Georgia Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $552 million in 2010, $506 million in 2009, and $490 million in 2008. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission 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 an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $473 million in 2010, $398 million in 2009, and $410 million in 2008.

The Company has entered into several power purchase agreements (PPA) with Southern Power for capacity and energy. Expenses associated with these PPAs were $199 million, $411 million, and $480 million in 2010, 2009, and 2008, respectively. Additionally, the Company had $26 million and $24 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2010 and 2009, respectively. See Note 7 under "Purchased Power Commitments" for additional information.

The Company has an agreement with Gulf Power under which Gulf Power jointly owns a portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $9 million in 2010, $4 million in 2009, and $8 million in 2008. See Note 4 for additional information.

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

Also see Note 4 for information regarding the Company's ownership in and a PPA with Southern Electric Generating Company (SEGCO) and Note 5 for information on certain deferred tax liabilities due to affiliates.

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

Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of governmental 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 millions)		
Deferred income tax charges	**$ 676**	$ 609	(a)
Deferred income tax charges – Medicare subsidy	**51**	-	(e)
Loss on reacquired debt	**176**	157	(b)
Vacation pay	**78**	75	(c, h)
Retiree benefit plans	**883**	952	(e, h)
Fuel-hedging (realized and unrealized) losses	**108**	82	(f)
Building leases	**45**	47	(i)
Generating plant outage costs	**31**	39	(j)
Other regulatory assets	**40**	49	(d)
Asset retirement obligations	**69**	116	(a, h)
Other cost of removal obligations	**(162)**	(341)	(a)
Deferred income tax credits	**(129)**	(134)	(a)
Environmental compliance cost recovery	**-**	(96)	(g)
Other regulatory liabilities	**(1)**	(1)	(b, f)
Total assets (liabilities), net	**$1,865**	$1,554	

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

(a) Asset retirement and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and other cost of removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2010, other cost of removal obligations included $92 million that will be amortized over a three-year period beginning January 1, 2011 in accordance with a Georgia PSC order. See Note 3 under “Retail Regulatory Matters – Rate Plans” for additional information.

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

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

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

(e) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 under “Pension Plans” and “Other Postretirement Benefits” and Note 5 under “Current and Deferred Income Taxes” for additional information.

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

(g) Deferred revenue associated with the levelization of the environmental compliance cost recovery (ECCR) tariff revenues for the years 2008 through 2010 in accordance with a Georgia PSC order.

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

(i) See Note 6 under “Capital Leases.” Recovered over the remaining lives of the buildings through 2026.

(j) See “Property, Plant, and Equipment.” Recovered over the respective operating cycles, which range from 18 months to 10 years.

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 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 and the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under “Nuclear Fuel Disposal Costs” for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are “more likely than not” of being sustained upon examination by the appropriate taxing authorities. See Note 5 under “Unrecognized Tax Benefits” for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost, less 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 millions)	
Generation	**$ 12,852**	$ 12,185
Transmission	**4,187**	3,891
Distribution	**7,855**	7,603
General	**1,475**	1,413
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 26,397**	$ 25,120

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit’s operating cycle. The refueling cycles are 18 and 24 months for Plants Vogtle and Hatch, respectively. Also, in accordance with a Georgia PSC order, the Company defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

The amount of non-cash property additions recognized for the years ended December 31, 2010, 2009 and 2008 was $310 million, $243 million, and $137 million, respectively. These amounts were comprised of construction related accounts payable outstanding at each year end together with retention amounts accrued during the respective year.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.0% in 2010 and 2009 and 2.9% in 2008. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. Effective January 1, 2011, the Company's depreciation rates were revised by the Georgia PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In August 2009, the Georgia PSC approved an accounting order allowing the Company to amortize a portion of its regulatory liability related to other cost of removal obligations. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability. See Note 3 under "Retail Regulatory Matters - Rate Plans" for additional information related to the Company's cost of removal regulatory liability.

The asset retirement obligation liability primarily relates to the Company's nuclear facilities, which include the Company's ownership interests in Plants Hatch and Vogtle. In addition, the Company has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income the allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

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

	2010	2009
	(in millions)	
Balance at beginning of year	**$ 681**	$ 690
Liabilities incurred	**-**	2
Liabilities settled	**(12)**	(7)
Accretion	**43**	44
Cash flow revisions	**-**	(48)
Balance at end of year	**$ 712**	$ 681

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (the Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities and the Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require, except for investments tied to market indices or other mutual funds, that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates. In addition, the NRC prohibits investments in securities of power reactor licensees. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the Company's management. The Funds' managers are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

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

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to investment brokers for a fee. Securities so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2010 and 2009, approximately $141 million and $14 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $144 million and $14 million at December 31, 2010 and 2009, respectively, and can only be sold upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2010, investment securities in the Funds totaled $818 million, consisting of equity securities of $258 million, debt securities of $493 million, and $67 million of other securities. At December 31, 2009, investment securities in the Funds totaled $580 million, consisting of equity securities of $429 million, debt securities of $138 million, and $13 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $1.8 billion, $984 million, and $412 million in 2010, 2009, and 2008, respectively, all of which were reinvested. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $74 million, of which $25 million of losses related to securities held in the Funds at December 31, 2010. For 2009, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $119 million, of which $118 million related to securities held in the Funds at December 31, 2009. For 2008, fair value reductions, including reinvested interest and dividends and excluding the Funds' expenses, were $(144) million. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning are based on the most current study performed in 2009. The site study costs and accumulated provisions for decommissioning as of December 31, 2010 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2063	2067
Site study costs:	*(in millions)*	
Radiated structures	$ 583	$ 500
Non-radiated structures	46	71
Total site study costs	$ 629	$ 571
Accumulated provision	$ 360	$ 206

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

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2006. The NRC estimates are $575 million and $420 million for Plant Hatch and Plant Vogtle Units 1 and 2 , respectively. The Georgia PSC approved annual decommissioning costs for ratemaking of $3 million annually for Plant Vogtle Units 1 and 2 for 2008 through 2010. Under the Company's alternate rate plan, effective January 1, 2011 and continuing through December 31, 2013 (2010 ARP), the annual decommissioning cost for ratemaking is $2 million for Plant Hatch. Based on estimates approved in the 2010 ARP, the Company projects the external trust funds for Plant Vogtle Units 1 and 2 would be adequate to meet the decommissioning obligations of the NRC with no further contributions. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4%. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs.

Allowance for Funds Used During Construction (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 facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2010, 2009, and 2008, the average AFUDC rates were 8.0%, 8.0%, and 8.2%, respectively, and AFUDC capitalized was $201 million, $137 million, and $135 million, respectively. AFUDC, net of income taxes, was 19.0%, 14.9%, and 13.3% of net income after dividends on preferred and preference stock 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 to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Storm Damage Reserve

The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. Under the retail rate plan effective January 1, 2008 (2007 Retail Rate Plan), the Company accrued $21 million annually that was recoverable through base rates. Starting January 1, 2011, the Company will accrue $18 million annually under the 2010 ARP. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

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 costs 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 Georgia PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in “Other” or shown separately as “Risk Management Activities”) and are measured at fair value. See Note 10 for additional information. Substantially all of the Company’s bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the “normal” scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel hedging program. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company 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.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. However, the Company is not considered the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as other investments, and the related loans from the trusts are reflected as long-term debt in the balance sheets. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information.

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 $168 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 postretirement trusts to the extent required by the FERC. For the year ending December 31, 2011, other postretirement trust contributions are expected to total approximately $22 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 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	**5.52%**	5.93%	6.75%
Other postretirement benefit plans	**5.40**	5.83	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	**7.24**	7.35	7.38

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 millions)	
Benefit obligation	$ 63	$ 54
Service and interest costs	3	3

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.5 billion in 2010 and $2.4 billion 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 millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,517**	$ 2,238
Service cost	**54**	48
Interest cost	**145**	147
Benefits paid	**(127)**	(122)
Actuarial loss (gain)	**85**	206
Balance at end of year	**2,674**	2,517
Change in plan assets		
Fair value of plan assets at beginning of year	**2,237**	2,038
Actual return (loss) on plan assets	**335**	314
Employer contributions	**176**	7
Benefits paid	**(127)**	(122)
Fair value of plan assets at end of year	**2,621**	2,237
Accrued liability	**$ (53)**	$ (280)

At December 31, 2010, the projected benefit obligations for the qualified and non-qualified pension plans were $2.5 billion and $144 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 millions)	
Prepaid pension costs	**$ 91**	$ -
Other regulatory assets, deferred	**689**	734
Current liabilities, other	**(9)**	(8)
Employee benefit obligations	**(135)**	(272)

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 millions)	
Prior service cost	**$ 61**	$ 73	**$ 12**
Net (gain) loss	**628**	661	**6**
Other regulatory assets, deferred	**$ 689**	$ 734	

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 millions)
Balance at December 31, 2008	$ 642
Net loss	108
Change in prior service costs	-
Reclassification adjustments:	
Amortization of prior service costs	(14)
Amortization of net gain	(2)
Total reclassification adjustments	(16)
Total change	92
Balance at December 31, 2009	$ 734
Net (gain)	**(30)**
Change in prior service costs	**-**
Reclassification adjustments:	
Amortization of prior service costs	**(13)**
Amortization of net gain	**(2)**
Total reclassification adjustments	**(15)**
Total change	**(45)**
Balance at December 31, 2010	**$ 689**

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

	2010	2009	2008
		(in millions)	
Service cost	**$ 54**	$ 48	$ 49
Interest cost	**145**	147	134
Expected return on plan assets	**(220)**	(216)	(211)
Recognized net loss	**2**	2	3
Net amortization	**13**	14	14
Net periodic pension cost (income)	**$ (6)**	$ (5)	$ (11)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2010, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2011	$ 139
2012	144
2013	149
2014	154
2015	160
2016 to 2020	889

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 millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 782**	$ 772
Service cost	**9**	10
Interest cost	**44**	50
Benefits paid	**(44)**	(43)
Actuarial (gain)/loss	**(7)**	8
Plan amendments	**-**	(18)
Retiree drug subsidy	**2**	3
Balance at end of year	**786**	782
Change in plan assets		
Fair value of plan assets at beginning of year	**369**	312
Actual return (loss) on plan assets	**37**	66
Employer contributions	**29**	31
Benefits paid	**(42)**	(40)
Fair value of plan assets at end of year	**393**	369
Accrued liability	**$ (393)**	$ (413)

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 millions)	
Regulatory assets	**$ 179**	$ 202
Employee benefit obligations	**(393)**	(413)

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 millions)	
Prior service cost	**$ 10**	$ 11	**$ 1**
Net (gain) loss	**152**	167	**3**
Transition obligation	**17**	24	**7**
Regulatory assets	**$ 179**	$ 202	

The changes in the balance of regulatory assets, 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
	(in millions)
Balance at December 31, 2008	$ 261
Net gain	(28)
Change in prior service costs/transition obligation	(18)
Reclassification adjustments:	
Amortization of transition obligation	(8)
Amortization of prior service costs	(2)
Amortization of net gain	(3)
Total reclassification adjustments	(13)
Total change	(59)
Balance at December 31, 2009	$ 202
Net gain	**(13)**
Change in prior service costs/transition obligation	**-**
Reclassification adjustments:	
Amortization of transition obligation	**(6)**
Amortization of prior service costs	**(1)**
Amortization of net gain	**(3)**
Total reclassification adjustments	**(10)**
Total change	**(23)**
Balance at December 31, 2010	**$ 179**

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

	2010	2009	2008
		(in millions)	
Service cost	**$ 9**	$ 10	$ 10
Interest cost	**44**	50	50
Expected return on plan assets	**(30)**	(30)	(30)
Net amortization	**10**	13	16
Net postretirement cost	**$ 33**	$ 43	$ 46

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 $11 million, $14 million, and $14 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 millions)	
2011	$ 50	$ (3)	$ 47
2012	52	(4)	48
2013	54	(4)	50
2014	57	(5)	52
2015	59	(5)	54
2016 to 2020	307	(29)	278

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	41%	**41%**	34%
International equity	22	**24**	29
Fixed income	31	**30**	32
Special situations	1	**-**	-
Real estate investments	3	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

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

Investment Strategies

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

- ***Domestic equity.*** A mix of large and small capitalization stocks with an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance.*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.

- ***Special situations.*** 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 millions)		
Assets:				
Domestic equity*	$ 486	$ 196	$ -	$ 682
International equity*	490	170	-	660
Fixed income:				
U.S. Treasury, government, and agency bonds	-	117	-	117
Mortgage- and asset-backed securities	-	95	-	95
Corporate bonds	-	226	1	227
Pooled funds	-	77	-	77
Cash equivalents and other	1	183	-	184
Special situations	-	-	-	-
Real estate investments	71	-	258	329
Private equity	-	-	245	245
Total	$ 1,048	$ 1,064	$ 504	$ 2,616

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

	Fair Value Measurements Using			
As of December 31, 2009:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$ 444	$ 184	$ -	$ 628
International equity*	574	57	-	631
Fixed income:				
U.S. Treasury, government, and agency bonds	-	165	-	165
Mortgage- and asset-backed securities	-	45	-	45
Corporate bonds	-	111	-	111
Pooled funds	-	4	-	4
Cash equivalents and other	1	136	-	137
Special situations	-	-	-	-
Real estate investments	69	-	217	286
Private equity	-	-	221	221
Total	$ 1,088	$ 702	$ 438	$ 2,228
Liabilities:				
Derivatives	(2)	-	-	(2)
Total	$ 1,086	$ 702	$ 438	$ 2,226

*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 millions)		
Beginning balance	**$ 217**	**$ 221**	$ 336	$ 196
Actual return on investments:				
Related to investments held at year end	**15**	**18**	(98)	14
Related to investments sold during the year	**7**	**7**	(26)	4
Total return on investments	**22**	**25**	(124)	18
Purchases, sales, and settlements	**19**	**(1)**	5	7
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$ 258**	**$ 245**	$ 217	$ 221

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 millions)		
Assets:				
Domestic equity*	$ 98	$ 33	$ -	$ 131
International equity*	16	39	-	55
Fixed income:				
U.S. Treasury, government, and agency bonds	-	4	-	4
Mortgage- and asset-backed securities	-	3	-	3
Corporate bonds	-	7	-	7
Pooled funds	-	28	-	28
Cash equivalents and other	-	11	-	11
Trust-owned life insurance	-	132	-	132
Special situations	-	-	-	-
Real estate investments	2	-	8	10
Private equity	-	-	8	8
Total	$ 116	$ 257	$ 16	$ 389

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

	Fair Value Measurements Using			
As of December 31, 2009:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$ 82	$ 29	$ -	$ 111
International equity*	20	31	-	51
Fixed income:				
U.S. Treasury, government, and agency bonds	-	5	-	5
Mortgage- and asset-backed securities	-	2	-	2
Corporate bonds	-	4	-	4
Pooled funds	-	17	-	17
Cash equivalents and other	-	26	-	26
Trust-owned life insurance	-	126	-	126
Special situations	-	-	-	-
Real estate investments	2	-	8	10
Private equity	-	-	8	8
Total	$ 104	$ 240	$ 16	$ 360

*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 millions)		
Beginning balance	**$ 8**	**$ 8**	$ 12	$ 7
Actual return on investments:				
Related to investments held at year end	**-**	**-**	(3)	1
Related to investments sold during the year	**-**	**-**	(1)	-
Total return on investments	**-**	**-**	(4)	1
Purchases, sales, and settlements	**-**	**-**	-	-
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$ 8**	**$ 8**	$ 8	$ 8

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2010, 2009, and 2008 were $23 million, $25 million, and $25 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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 the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The action was filed concurrently with the issuance of a notice of violation of the NSR provisions to the Company. 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 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 the Company, 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 now be determined.

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 maintains a reserve for environmental remediation as mandated by the Georgia PSC. The Company accrued $1 million annually for environmental remediation expenses during 2008 through 2010 that was recoverable through its ECCR tariff. Beginning in 2011, the Company is accruing approximately $3 million annually under the 2010 ARP. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As of December 31, 2010, the balance of the environmental remediation liability was $13 million, with approximately $3 million included in other regulatory assets, current and approximately $3 million included as other regulatory assets, deferred.

The Company has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and the CERCLA NPL are anticipated. The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the financial statements.

In September 2008, the EPA advised the Company that it has been designated as a PRP at the Ward Transformer Superfund site located in Raleigh, North Carolina. Numerous other entities have also received notices regarding this site from the EPA. The Company, along with other named PRPs, is negotiating with the EPA to address cleanup of the site and reimbursement for past expenditures related to work performed at the site. In addition, in April 2009, two PRPs filed separate actions in the U.S. District Court for the Eastern District of North Carolina against numerous other PRPs, including the Company, seeking contribution from the defendants for expenses incurred by the plaintiffs related to work performed at a portion of the site. The ultimate outcome of these matters will depend upon further environmental assessment and the ultimate number of PRPs and cannot be determined at this time; however, as a result of the regulatory treatment previously described, it is not expected to have a material impact on the Company's financial statements.

Income Tax Matters

Georgia State Income Tax Credits

The Company's 2005 through 2009 income tax filings for the State of Georgia include state income tax credits for increased activity through Georgia ports. The Company filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue (DOR) has not responded to these claims. In July 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On March 22, 2010, the Superior Court of Fulton County ruled in favor of the Company's motion for summary judgment. The Georgia DOR has appealed to the Georgia Court of Appeals and a decision is expected later this year. Any decision may be subject to further appeal to the Georgia Supreme Court. An unrecognized tax benefit has been recorded related to these credits. If the Company prevails, no material impact on the Company's net income is expected as a significant portion of any tax benefit is expected to be returned to retail customers in accordance with the 2010 ARP. If the Company is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on the Company's cash flow. See Note 5 under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot be determined at this time.

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 $133 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. The ultimate outcome of this matter cannot be determined at this time. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Nuclear Fuel Disposal Costs

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

In July 2007, the U.S. Court of Federal Claims awarded the Company approximately $30 million, based on its ownership interests, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plants Hatch and Vogtle from 1998 through 2004. In November 2007, the government's motion for reconsideration was denied. In January 2008, the government filed an appeal and, in February 2008, filed a motion to stay the appeal, which the U.S. Court of Appeals for the Federal Circuit granted in April 2008. On May 5, 2010, the U.S. Court of Appeals for the Federal Circuit lifted the stay.

In April 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim), due to the government's alleged continuing breach of contract. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2010 for either claim. The final outcome of these matters cannot be determined at this time, but no material impact on the Company's net income is expected as any damage amounts collected from the government are expected to be returned to customers.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry spent fuel storage facility is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Retail Regulatory Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 under the 2007 Retail Rate Plan. In June 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of filing to increase customer rates as allowed under the 2007 Retail Rate Plan, in June 2009, the Company filed a request with the Georgia PSC for an accounting order that would allow the Company to amortize up to $324 million of its regulatory liability related to other cost of removal obligations.

In August 2009, the Georgia PSC approved the accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million of the regulatory liability, respectively.

On December 21, 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff (PSC Staff), and eight other intervenors. Under the terms of the 2010 ARP, the Company will amortize approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

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

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

- Effective January 1, 2012, the DSM tariffs will increase by $17 million;
- Effective April 1, 2012, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4 and 5 for the period from commercial operation through December 31, 2013;
- Effective January 1, 2013, the DSM tariffs will increase by $18 million;
- Effective January 1, 2013, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Unit 6 for the period from commercial operation through December 31, 2013; and
- The MFF tariff will increase consistent with these adjustments.

The Company currently estimates these adjustments will result in annualized base revenue increases of approximately $190 million in 2012 and $93 million in 2013.

Under the 2010 ARP, the Company's retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25 % will be directly refunded to customers, with the remaining one-third retained by the Company. If at any time during the term of the 2010 ARP, the Company projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust the Company's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, the Company may file a full rate case.

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

The Company currently expects to file an update to its integrated resource plan in June 2011. Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets (resulting from new or revised environmental regulations) through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. Such costs that may be deferred as a regulatory asset include any impairment losses that may result from a decision to retire certain units that are no longer cost effective in light of new or modified environmental regulations. In addition, in connection with the 2010 ARP, the Georgia PSC also approved revised depreciation rates that will recover the remaining book value of certain of the Company's existing coal-fired units by December 31, 2014. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved increases in the Company's total annual billings of approximately $222 million effective June 1, 2008 and $373 million effective April 1, 2010. In addition, the Georgia PSC has authorized an interim fuel rider, which would allow the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds budget by more than $75 million. The Company is currently required to file its next fuel case by March 1, 2011.

The Company's under recovered fuel balance totaled approximately $398 million, of which approximately $214 million is included in deferred charges and other assets in the balance sheets at December 31, 2010.

Fuel cost recovery revenues as recorded in the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, a change in the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow.

Construction

Nuclear

In August 2009, the NRC issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of the Company, Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), related to two additional nuclear units on the site of Plant Vogtle (Plant Vogtle Units 3 and 4). See Note 4 for additional information on these co-owners. In March 2008, Southern Nuclear filed an application with the NRC for a combined construction and operating license (COL) for the new units. If licensed by the NRC, Plant Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively.

In April 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COL or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In March 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve the inclusion of the related construction work in progress accounts in rate base. In April 2009, the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows the Company to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allows the Company to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. The Georgia PSC has ordered the Company to report against this total certified cost of approximately $6.1 billion. In addition, on December 21, 2010, the Georgia PSC approved the Company's Nuclear Construction Cost Recovery (NCCR) tariff. The NCCR tariff became effective January 1, 2011 and is expected to collect approximately $223 million in revenues during 2011.

On February 21, 2011, the Georgia PSC voted to approve the Company's third semi-annual construction monitoring report including total costs of $1.048 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2010. In connection with its certification of Vogtle Units 3 and 4, the Georgia PSC ordered the Company and the PSC Staff to work together to develop a risk sharing or incentive mechanism that would provide some level of protection to ratepayers in the event of significant cost overruns, but also not penalize the Company's earnings if and when overruns are due to mandates from governing agencies. Such discussions have continued through the third semi-annual construction monitoring proceedings; however, the Georgia PSC has deferred a decision with respect to any related incentive or risk-sharing mechanism until a later date. The Company will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In 2009, the Southern Alliance for Clean Energy (SACE) and the Fulton County Taxpayers Foundation, Inc. (FCTF) filed separate petitions in the Superior Court of Fulton County, Georgia seeking review of the Georgia PSC's certification order and challenging the constitutionality of the Georgia Nuclear Energy Financing Act. On May 5, 2010, the court dismissed as premature the plaintiffs' claim challenging the Georgia Nuclear Energy Financing Act. FCTF appealed the decision, and the Georgia Supreme Court ruled against FCTF, finding the suit premature. In addition, on May 5, 2010, the Superior Court of Fulton County issued an order remanding the Georgia PSC's certification order for inclusion of further findings of fact and conclusions of law by the Georgia PSC. In compliance with the court's order, the Georgia PSC issued its order on remand to include further findings of fact and conclusions of law on June 23, 2010. On July 5, 2010, SACE and FCTF filed separate motions with the Georgia PSC for reconsideration of the order on remand. On August 17, 2010, the Georgia PSC voted to reaffirm its order. The matter is no longer subject to judicial review and is now concluded.

On December 2, 2010, Westinghouse submitted an AP1000 Design Certification Amendment (DCA) to the NRC. On February 10, 2011, the NRC announced that it was seeking public comment on a proposed rule to approve the DCA and amend the certified AP1000 reactor design for use in the U.S. The Advisory Committee on Reactor Safeguards also issued a letter on January 24, 2011 endorsing the issuance of the COL for Plant Vogtle Units 3 and 4. The Company currently expects to receive the COL for Plant Vogtle Units 3 and 4 from the NRC in late 2011 based on the NRC's February 16, 2011 release of its COL schedule framework.

There are other pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4. Similar additional challenges at the state and federal level are expected as construction proceeds.

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

Other Construction

On May 6, 2010, the Georgia PSC approved the Company's request to extend the construction schedule for Plant McDonough Units 4, 5, and 6 as a result of the short-term reduction in forecasted demand, as well as the requested increase in the certified amount. As a result, the units are expected to be placed into service in January 2012, May 2012, and January 2013, respectively. To date, the Georgia PSC has approved the Company's quarterly construction monitoring reports including actual project expenditures incurred through June 30, 2010. The Company will continue to file quarterly construction monitoring reports throughout the construction period.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, debt service, and return on investment, whether or not SEGCO has any capacity and energy available. The term of the contract extends automatically for two-year periods, subject to either party's right to cancel upon two years' notice. The Company accounts for SEGCO using the equity method.

The Company's share of expenses included in purchased power from affiliates in the statements of income is as follows:

	2010	2009	2008
		(in millions)	
Energy	**$ 53**	$ 44	$ 86
Capacity	**47**	43	41
Total	**$ 100**	$ 87	$ 127

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with OPC, MEAG Power, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company and Florida Power Corporation (Progress Energy Florida) jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida.

At December 31, 2010, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership	Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)			
Units 1 and 2	45.7%	$ 3,292	$ 1,935
Plant Hatch (nuclear)	50.1	962	534
Plant Wansley (coal)	53.5	700	208
Plant Scherer (coal)			
Units 1 and 2	8.4	148	74
Unit 3	75.0	857	362
Rocky Mountain (pumped storage)	25.4	175	109
Intercession City (combustion-turbine)	33.3	12	3

At December 31, 2010, the portion of total construction work in progress related to Plants Wansley, Scherer, and Vogtle Units 3 and 4 was $11 million, $110 million, and $1.3 billion, respectively. Construction at Plants Wansley and Scherer relates primarily to environmental projects. See Note 3 under "Construction – Nuclear" for information on Plant Vogtle Units 3 and 4.

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

5. INCOME TAXES

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

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2010	2009	2008
		(in millions)	
Federal –			
Current	**$ 147**	$ 211	$ 284
Deferred	**312**	175	155
	459	386	439
State –			
Current	**(36)**	7	33
Deferred	**30**	17	16
	(6)	24	49
Total	**$ 453**	$ 410	$ 488

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 millions)	
Deferred tax liabilities –		
Accelerated depreciation	**$ 3,184**	$ 2,923
Property basis differences	**746**	585
Employee benefit obligations	**251**	184
Fuel clause under recovery	**162**	270
Premium on reacquired debt	**71**	64
Emissions allowances	**18**	22
Regulatory assets associated with employee benefit obligations	**336**	362
Asset retirement obligations	**275**	263
Other	**52**	70
Total	**5,095**	4,743
Deferred tax assets –		
Federal effect of state deferred taxes	**159**	177
Employee benefit obligations	**433**	482
Other property basis differences	**111**	117
Other deferred costs	**72**	65
Cost of removal obligations	**52**	109
State tax credit carry forward	**192**	99
Other comprehensive income	**6**	12
Unbilled fuel revenue	**57**	42
Asset retirement obligations	**275**	263
Environmental capital cost recovery	**1**	37
Other	**37**	38
Total	**1,395**	1,441
Total deferred tax liabilities, net	**3,700**	3,302
Portion included in current assets/(liabilities), net	**18**	88
Accumulated deferred income taxes	**$ 3,718**	$ 3,390

At December 31, 2010, tax-related regulatory assets were $727 million and tax-related regulatory liabilities were $129 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 interest. In 2010, the Company deferred $51 million as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of health care costs that are covered by federal Medicare subsidy payments. Beginning in 2011, the Company is amortizing the regulatory asset to income tax expense over 12 years, under the 2010 ARP. These liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $13 million in 2010, $14 million in 2009, and $13 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 tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2010	2009	2008
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**(0.3)**	1.2	2.2
Non-deductible book depreciation	**1.0**	1.1	0.9
AFUDC equity	**(3.6)**	(2.7)	(2.4)
Donations	**-**	(0.8)	-
Other	**(0.2)**	(0.8)	(1.1)
Effective income tax rate	**31.9%**	33.0%	34.6%

The decreases in the Company's 2010 and 2009 effective tax rates are primarily the result of increases in non-taxable AFUDC equity and state tax credits. See "Unrecognized Tax Benefits" herein and Note 3 under "Income Tax Matters" for additional information on unrecognized tax benefits and related litigation related to state tax credits.

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. 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 $56 million, resulting in a balance of $237 million as of December 31, 2010.

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

	2010	2009	2008
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 181**	$ 137	$ 89
Tax positions from current periods	**52**	44	47
Tax positions increase from prior periods	**27**	6	5
Tax positions decrease from prior periods	**(23)**	(5)	-
Reductions due to settlements	**-**	-	(4)
Reductions due to expired statute of limitations	**-**	(1)	-
Balance at end of year	**$ 237**	$ 181	$ 137

The tax positions from current periods relates primarily to the Georgia state tax credits litigation, tax accounting method change for repairs 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 positions. The tax positions decrease from prior periods relates primarily to the Georgia state tax credit litigation and miscellaneous tax positions. See Note 3 under "Income Tax Matters" for additional information.

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

	2010	2009	2008
		(in millions)	
Tax positions impacting the effective tax rate	**$ 202**	$ 181	$ 134
Tax positions not impacting the effective tax rate	**35**	-	3
Balance of unrecognized tax benefits	**$ 237**	$ 181	$ 137

The tax positions impacting the effective tax rate primarily relate to the state tax credit litigation, however, as discussed in Note 3 under "Income Tax Matters," if the Company is successful in its claim against the DOR, a significant portion of the tax benefit is expected to be deferred and returned to retail customers and therefore no material impact to net income is expected. 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 millions)	
Interest accrued at beginning of year	**$ 20**	$ 14	$ 7
Interest accrued during the year	**7**	6	7
Balance at end of year	**$ 27**	$ 20	$ 14

The Company classifies interest on tax uncertainties as interest expense. The net amount of interest accrued for all years presented was primarily associated with the state tax credit litigation. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the state tax credit litigation would substantially reduce the balances. 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

Long-Term Debt Payable to Affiliated Trusts

The Company has formed certain wholly-owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as long-term debt. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2010, preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

A summary of the scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2010	2009
	(in millions)	
Capital lease	**$ 4**	$ 4
Bank term loan	**300**	-
Pollution control revenue bonds	**8**	-
Senior notes	**100**	250
Other long-term debt	**3**	-
Total	**$ 415**	$ 254

Maturities through 2015 applicable to total long-term debt are as follows: $415 million in 2011; $205 million in 2012; $1.4 billion in 2013; $5 million in 2014; and $256 million in 2015.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company has incurred obligations in connection with the sale by public authorities of tax-exempt pollution control revenue bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2010 and 2009 was $1.5 billion and $2.0 billion, respectively. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Senior Notes

The Company issued $2.0 billion aggregate principal amount of unsecured senior notes in 2010. The proceeds of the issuance were used to repay a portion of the Company's short-term indebtedness, fund note redemptions totaling $1.1 billion, redeem pollution control revenue bonds totaling $516 million, and fund the Company's continuous construction program.

At December 31, 2010 and 2009, the Company had $6.3 billion and $5.4 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $59 million and $63 million at December 31, 2010 and 2009, respectively.

Subsequent to December 31, 2010, the Company issued $300 million of Series 2011A Floating Rate Senior Notes due January 15, 2013. The proceeds from the sale of the Series 2011A Senior Notes were used by the Company to repay a portion of its outstanding short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

Bank Term Loans

At December 31, 2010 and 2009, the Company had a $300 million bank loan outstanding, which matures in March 2011.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2010 and 2009, the Company had a capitalized lease obligation for its corporate headquarters building of $58 million and $62 million, respectively, with an interest rate of 8.0%. For ratemaking purposes, the Georgia PSC has treated the lease as an operating lease and has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. See Note 1 under "Regulatory Assets and Liabilities." The annual expense incurred for all capital leases in 2010, 2009, and 2008 was $6 million, $9 million, and $10 million, respectively.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the Class A preferred stock and preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the stock. In addition, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends through the first par redemption date.

Dividend Restrictions

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

Bank Credit Arrangements

At December 31, 2010, the Company had credit arrangements with banks totaling $1.7 billion, of which $12 million was used to support outstanding letters of credit. Of these facilities, $595 million expire during 2011, with the remaining $1.1 billion expiring in 2012. Of the facilities that expire in 2011, $40 million provides the option of converting borrowings into a two-year term loan and $220 million provides the option of converting borrowings into a one-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. All the agreements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

The credit arrangements contain covenants that limit the ratio of indebtedness to capitalization (each as defined in the arrangements) to 65%. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts and, in certain cases, other hybrid securities. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2010, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $1.7 billion of unused credit arrangements provides liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2010 was $385 million. Subsequent to December 31, 2010, the Company's remarketing of $137 million of variable rate pollution control revenue bonds increased the total requiring liquidity support to $522 million. In addition, the Company borrows under a commercial paper program. The amount of commercial paper outstanding at December 31, 2010 and 2009 was $575 million and $324 million, respectively. Commercial paper and short-term bank loans are included in notes payable on the balance sheets.

During 2010, the maximum amount of commercial paper outstanding was $575 million and the average amount outstanding was $167 million. During 2009, the maximum amount of commercial paper outstanding was $757 million and the average amount outstanding was $348 million. The weighted average annual interest rate on commercial paper in 2010 and 2009 was 0.3% and 0.4%, respectively.

7. COMMITMENTS

Construction Program

The construction program of the Company is currently estimated to include a base level investment of $2.1 billion, $2.2 billion, and $2.0 billion for 2011, 2012, and 2013, respectively. These amounts include $252 million, $148 million, and $185 million in 2011, 2012, and 2013, respectively, for construction expenditures related to contractual purchase commitments for nuclear fuel included herein under "Fuel Commitments." Included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $73 million, $79 million, and $58 million for 2011, 2012, and 2013, respectively. The capital budget amounts for 2011-2013 include amounts for the construction of Plant Vogtle Units 3 and 4 as discussed in Note 3 under "Construction – Nuclear." Of the estimated total $4.4 billion in capital costs, approximately $943 million is expected to be incurred from 2014 through 2017. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2010, significant purchase commitments were outstanding in connection with the ongoing construction program. See Note 3 under "Construction" for additional information.

Long-Term Service Agreements

The Company has a long-term service agreement (LTSA) with General Electric (GE) for maintenance support for the combustion turbines at the Plant McIntosh combined cycle facility. In summary, the LTSA stipulates that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in the contract. In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE, which are subject to price escalation, are made quarterly based on actual operating hours of the respective units. Total payments to GE are currently estimated at $155 million over the remaining term of the agreement, which is currently projected to be approximately eight years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company also has a LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $6 million. The contract contains cancellation provisions at the option of the Company. Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense, as appropriate, net of any joint owner billings, based on the nature of the work.

The Company has entered into a LTSA with Mitsubishi Power Systems Americas, Inc. (MPS) for the purpose of providing certain parts and maintenance services for the three combined cycle units under construction at Plant McDonough, which are scheduled to go into service in January 2012, May 2012, and January 2013, respectively. The LTSA stipulates that MPS will perform all planned maintenance on each covered unit which includes the cost of all materials and services. MPS is also obligated to cover costs of unplanned maintenance on the gas turbines subject to limits specified in the LTSA. This LTSA will begin in 2012 and is in effect through two major inspection cycles per covered unit. Periodic payments to MPS are to be made quarterly and will also be made based on the scheduled inspections for the respective covered units. Payments to MPS, which are subject to price escalation, are currently estimated to be $537 million for the term of this agreement which is expected to be between 12 and 13 years. However, the LTSA contains various termination provisions at the option of the Company.

Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 3.5 million tons, equating to approximately $93 million through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are $17 million in 2011, $18 million in 2012, $18 million in 2013, $19 million in 2014, and $11 million in 2015.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emissions allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2010.

Total estimated minimum long-term commitments at December 31, 2010 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2011	$ 445	$ 1,869	$ 252
2012	490	808	148
2013	494	730	185
2014	429	441	165
2015	340	345	98
2016 and thereafter	2,665	1,182	585
Total	$4,863	$ 5,375	$ 1,433

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense amounted to $106 million, $82 million, and $77 million for the years 2010, 2009, and 2008, respectively.

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

Purchased Power Commitments

The Company has commitments regarding a portion of a 5% interest in Plant Vogtle owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of Plant Vogtle's allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $55 million, $54 million, and $48 million in 2010, 2009, and 2008, respectively. The Company also has entered into other various long-term PPAs. Estimated total long-term obligations under these commitments at December 31, 2010 were as follows:

	Vogtle Capacity Payments	Affiliated PPAs	Non-Affiliated PPAs
		(in millions)	
2011	$ 55	$ 119	$ 142
2012	49	107	115
2013	23	107	108
2014	18	108	109
2015	11	108	110
2016 and thereafter	87	380	1,259
Total	$ 243	$ 929	$ 1,843

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

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $35 million for 2010, $43 million for 2009, and $52 million for 2008.

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

	Minimum Lease Payments		
	Rail Cars	Other	Total
		(in millions)	
2011	$ 30	$ 6	$ 36
2012	17	4	21
2013	12	4	16
2014	10	3	13
2015	8	1	9
2016 and thereafter	7	1	8
Total	$ 84	$ 19	$ 103

In addition to the above rental commitments, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These leases expire in 2011 and the Company's maximum obligation is $40 million. At the termination of the leases, at the Company's option, the Company may either exercise its purchase option or the property can be sold to a third party. A portion of the rail car lease obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

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

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to rail car leases.

8. STOCK COMPENSATION

Stock 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 1,837 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	10,322,924	$31.90
Granted	1,715,600	31.19
Exercised	(1,656,754)	27.80
Cancelled	163	30.34
Outstanding at December 31, 2010	**10,381,933**	**$32.44**
Exercisable at December 31, 2010	**6,848,412**	**$32.77**

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. At 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 $60 million and $37 million, respectively. As of December 31, 2010, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. The amounts were not material for any year presented.

The total intrinsic value of options exercised during the years ended December 31, 2010, 2009, and 2008 was $12 million, $2 million, and $11 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises was not material for any year presented.

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

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. Expected volatility used in the model 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, 189,361 performance share units were granted to the Company's employees with a weighted-average grant date fair value of $30.13. During 2010, 3,849 performance share units were forfeited by the Company's employees resulting in 185,512 unvested units outstanding at December 31, 2010.

For the year ended December 31, 2010, the Company's total compensation cost for performance share units and the related tax benefit recognized in income were not material. As of December 31, 2010, the amount of total unrecognized compensation cost related to performance share award units that will be recognized over the next two years was not material.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's Plants Hatch and Vogtle. The Act provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests, is $237 million, per incident, but not more than an aggregate of $35 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

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

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

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $70 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes. In the event of a loss, the amount of insurance available may not be adequate to cover property damage and other incurred expenses.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

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

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

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

Valuation Methodologies

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

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

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

As of December 31, 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 millions)			
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$ 65	None	Daily	1 to 3 days
Other – commingled funds	$ 67	None	Daily	Not applicable

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

As of December 31, 2010 and 2009, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2010	**$ 8,285**	**$ 8,548**
2009	$ 7,973	$ 8,059

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

11. DERIVATIVES

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

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Georgia PSC, through the use of financial derivative contracts, and recently has started using significantly more financial options within the guidelines of the Georgia PSC which is expected to continue to mitigate price volatility.

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

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

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clauses.
- *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 totaled 59 million mmBtu (million British thermal units), all of which expire by 2015, which is the longest hedge date.

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

Interest Rate Derivatives

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

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

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2011 are $4 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

Derivative Financial Statement Presentation and Amounts

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

	Asset Derivatives			**Liability Derivatives**		
Derivative Category	**Balance Sheet Location**	**2010**	2009	**Balance Sheet Location**	**2010**	2009
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$1**	$-	Liabilities from risk management activities	**$77**	$47
	Other deferred charges and assets	**-**	-	Other deferred credits and liabilities	**24**	28
Total derivatives designated as hedging instruments for regulatory purposes		**$1**	$-		**$101**	$75
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**$-**	$-	Liabilities from risk management activities	**$-**	$2
Total		**$1**	$-		**$101**	$77

All derivative instruments are measured at fair value. See Note 10 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 millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$(77)**	$(47)	Other regulatory liabilities, current	**$1**	$-
	Other regulatory assets, deferred	**(24)**	(28)	Other deferred credits and liabilities	**-**	-
Total energy-related derivative gains (losses)		**$(101)**	$(75)		**$1**	$-

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 millions)				*(in millions)*	
Interest rate derivatives	**$ -**	$(3)	$(34)	Interest expense, net of amounts capitalized	**$(16)**	$(22)	$(3)

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. The Company has 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 $26 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 million.

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

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2010 and 2009 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2010	**$ 1,984**	**$ 399**	**$ 238**
June 2010	**2,000**	**411**	**238**
September 2010	**2,628**	**714**	**420**
December 2010	**1,737**	**141**	**54**
March 2009	$ 1,766	$ 272	$ 122
June 2009	1,874	369	190
September 2009	2,327	683	388
December 2009	1,725	206	114

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

[This page intentionally left blank]

SELECTED FINANCIAL AND OPERATING DATA 2006-2010

Georgia Power Company 2010 Annual Report

	2010	2009	2008	2007	2006
Operating Revenues (in millions)	**$8,349**	$7,692	$8,412	$7,572	$7,246
Net Income after Dividends on Preferred and Preference Stock (in millions)	**$950**	$814	$903	$836	$787
Cash Dividends on Common Stock (in millions)	**$820**	$739	$721	$690	$630
Return on Average Common Equity (percent)	**11.42**	11.01	13.56	13.50	13.80
Total Assets (in millions)	**$25,914**	$24,295	$22,316	$20,823	$19,309
Gross Property Additions (in millions)	**$2,401**	$2,646	$1,953	$1,862	$1,277
Capitalization (in millions)**:**					
Common stock equity	**$8,741**	$7,903	$6,879	$6,435	$5,956
Preferred and preference stock	**266**	266	266	266	45
Long-term debt	**7,931**	7,782	7,006	5,938	5,212
Total (excluding amounts due within one year)	**$16,938**	$15,951	$14,151	$12,639	$11,213
Capitalization Ratios (percent)**:**					
Common stock equity	**51.6**	49.5	48.6	50.9	53.1
Preferred and preference stock	**1.6**	1.7	1.9	2.1	0.4
Long-term debt	**46.8**	48.8	49.5	47.0	46.5
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end)**:**					
Residential	**2,049,770**	2,043,661	2,039,503	2,024,520	1,998,643
Commercial	**296,140**	295,375	295,925	295,478	294,654
Industrial	**8,136**	8,202	8,248	8,240	8,008
Other	**7,309**	6,580	5,566	4,807	4,371
Total	**2,361,355**	2,353,818	2,349,242	2,333,045	2,305,676
Employees (year-end)	**8,330**	8,599	9,337	9,270	9,278

N/A = Not Applicable.

	2010	2009	2008	2007	2006
Operating Revenues (in millions):					
Residential	**$ 3,072**	$2,686	$2,648	$2,443	$2,326
Commercial	**3,011**	2,826	2,917	2,576	2,424
Industrial	**1,441**	1,318	1,640	1,404	1,382
Other	**84**	82	81	75	74
Total retail	**7,608**	6,912	7,286	6,498	6,206
Wholesale - non-affiliates	**380**	395	569	538	552
Wholesale - affiliates	**53**	112	286	278	253
Total revenues from sales of electricity	**8,041**	7,419	8,141	7,314	7,011
Other revenues	**308**	273	271	258	235
Total	**$8,349**	$7,692	$8,412	$7,572	$7,246
Kilowatt-Hour Sales (in millions):					
Residential	**29,433**	26,272	26,412	26,840	26,206
Commercial	**33,855**	32,593	33,058	33,057	32,112
Industrial	**23,209**	21,810	24,164	25,490	25,577
Other	**663**	671	671	697	660
Total retail	**87,160**	81,346	84,305	86,084	84,555
Wholesale - non-affiliates	**4,662**	5,208	9,755	10,578	10,687
Wholesale - affiliates	**1,000**	2,504	3,695	5,192	5,463
Total	**92,822**	89,058	97,755	101,854	100,705
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**10.44**	10.22	10.03	9.10	8.88
Commercial	**8.89**	8.67	8.82	7.79	7.55
Industrial	**6.21**	6.04	6.79	5.51	5.40
Total retail	**8.73**	8.50	8.64	7.55	7.34
Wholesale	**7.65**	6.57	6.36	5.17	4.98
Total sales	**8.66**	8.33	8.33	7.18	6.96
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,367**	12,848	12,969	13,315	13,216
Residential Average Annual Revenue Per Customer	**$1,499**	$1,314	$1,300	$1,212	$1,173
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,992**	15,995	15,995	15,995	15,995
Maximum Peak-Hour Demand (megawatts):					
Winter	**15,614**	15,173	14,221	13,817	13,528
Summer	**17,152**	16,080	17,270	17,974	17,159
Annual Load Factor (percent)	**60.9**	60.7	58.4	57.5	61.8
Plant Availability (percent):					
Fossil-steam	**88.6**	92.5	91.0	90.8	91.4
Nuclear	**94.0**	88.4	89.8	92.4	90.7
Source of Energy Supply (percent):					
Coal	**51.8**	52.3	58.7	61.5	59.0
Nuclear	**16.4**	16.2	14.8	14.6	14.4
Hydro	**1.4**	1.8	0.6	0.5	0.9
Oil and gas	**8.0**	7.7	5.1	5.5	5.0
Purchased power -					
From non-affiliates	**5.2**	4.4	5.1	3.8	3.8
From affiliates	**17.2**	17.6	15.7	14.1	16.9
Total	**100.0**	100.0	100.0	100.0	100.0

GULF POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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. Our audits also included the financial statement schedule listed of the Company in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 II-287 to II-327) 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. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

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.

[This page intentionally left blank]

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
Gulf Power Company 2010 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 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. Certain prior years' data presented in the financial statement have been reclassified to conform to the current year presentation.

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 Real Estate Investments	2010 Private Equity	2009 Real Estate Investments	2009 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.

SELECTED FINANCIAL AND OPERATING DATA 2006-2010

Gulf Power Company 2010 Annual Report

	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

[This page intentionally left blank]

MISSISSIPPI POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Mississippi Power Company 2010 Annual Report

The management of Mississippi 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.

Edward Day, VI
President and Chief Executive Officer

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer

February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Mississippi Power Company

We have audited the accompanying balance sheets and statements of capitalization of Mississippi 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. Our audits also included the financial statement schedule of the Company listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 II-363 to II-407) present fairly, in all material respects, the financial position of Mississippi 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. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

Atlanta, Georgia
February 25, 2011

OVERVIEW

Business Activities

Mississippi Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Mississippi 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. The Company has various regulatory mechanisms that operate to address cost recovery.

Appropriately balancing required costs and capital expenditures with reasonable retail rates will continue to challenge the Company for the foreseeable future. Hurricane Katrina, the worst natural disaster in the Company's history, hit the Gulf Coast of Mississippi in August 2005, causing substantial damage to the Company's service territory. As of December 31, 2010, the Company had over 8,300 fewer retail customers as compared to pre-storm levels due to obstacles in the rebuilding process as a result of the storm, coupled with the recessionary economy. See Note 1 to the financial statements under "Government Grants" and Note 3 to the financial statements under "Retail Regulatory Matters − Storm Damage Cost Recovery" for additional information.

The Company's retail base rates are set under the Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi Public Service Commission (PSC). PEP was designed with the objective to reduce the impact of rate changes on customers and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high.

On June 3, 2010, the Mississippi PSC issued a certification of public convenience and necessity authorizing the acquisition, construction, and operation of a new integrated coal gasification combined cycle (IGCC) electric generating plant located in Kemper County, Mississippi, which is scheduled to be placed into service in 2014. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to over 185,000 customers, the Company continues to focus on several key indicators. These indicators are used to measure the Company's performance for customers and employees.

In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the Company's allowed return. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in outage minutes per customer (40%); and customer satisfaction, measured in a survey of residential customers (20%). See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

In addition to the PEP performance indicators, the Company focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock. The Company's financial success is directly tied to the satisfaction of its customers. Management uses customer satisfaction surveys 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 actual Peak Season EFOR performance for 2010 was one of the best in the history of the Company. Net income after dividends on preferred stock is the primary measure of the Company's financial performance. Recognizing the critical role in the Company's success played by the Company's employees, employee-related measures are a significant management focus. These measures include safety and inclusion. The 2010 safety performance of the Company was the third best in the history of the Company with an Occupational Safety and Health Administration Incidence Rate of 0.55. This achievement resulted in the Company being recognized as one of the top in safety performance among all utilities in the Southeastern Electric Exchange. Inclusion initiatives resulted in performance above target levels for the year.

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 overall and in all segments
Peak Season EFOR	5.06% or less	0.82%
Net income after dividends on preferred stock	$77.8 million	$80.2 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2010 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's net income after dividends on preferred stock was $80.2 million in 2010 compared to $85.0 million in 2009. The 5.6% decrease in 2010 was primarily the result of decreases in wholesale energy and capacity revenues from customers served outside the Company's service territory and increases in operations and maintenance expenses, depreciation and amortization, and taxes other than income taxes. These decreases in earnings were partially offset by increases in allowance for equity funds used during construction, revenues attributable to collection of Municipal and Rural Associations (MRA) emissions allowance cost with the Federal Energy Regulatory Commission's (FERC) December 2010 acceptance of the Company's wholesale filing made in October 2010, and territorial base revenues primarily resulting from warmer weather in the second and third quarters 2010 and colder weather in the first and fourth quarters 2010 compared to the corresponding periods in 2009.

The Company's net income after dividends on preferred stock was $85.0 million in 2009 compared to $86.0 million in 2008. The 1.2% decrease in 2009 was primarily the result of decreases in wholesale energy revenues and total other income and (expense) primarily resulting from an increase in interest expense and decreases in contracting work performed for customers, as well as an increase in income tax expense. These decreases in earnings were partially offset by an increase in territorial base revenues primarily due to a wholesale base rate increase accepted by the FERC effective in January 2009 and higher demand as well as a decrease in other non-fuel related expenses.

Net income after dividends on preferred stock was $86.0 million in 2008 compared to $84.0 million in 2007. The 2.4% increase in 2008 was primarily the result of an increase in territorial base revenues due to a retail base rate increase effective January 2008 and an increase in wholesale capacity revenues, partially offset by an increase in depreciation and amortization primarily due to the amortization of regulatory items, an increase in non-fuel related expenses, and an increase in charitable contributions. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year		
	2010	**2010**	2009	2008
		(in millions)		
Operating revenues	**$1,143.1**	**$(6.3)**	$(107.1)	$142.8
Fuel	**501.8**	**(17.8)**	(66.8)	92.2
Purchased power	**83.7**	**(8.3)**	(34.6)	30.7
Other operations and maintenance	**268.1**	**21.3**	(13.3)	4.8
Depreciation and amortization	**76.9**	**6.0**	(0.1)	10.7
Taxes other than income taxes	**69.8**	**5.7**	(1.0)	4.8
Total operating expenses	**1,000.3**	**6.9**	(115.8)	143.2
Operating income	**142.8**	**(13.2)**	8.7	(0.4)
Total other income and (expense)	**(14.6)**	**4.5**	(7.8)	(1.1)
Income taxes	**46.3**	**(3.9)**	1.9	(3.4)
Net income	**81.9**	**(4.8)**	(1.0)	1.9
Dividends on preferred stock	**1.7**	**-**	-	-
Net income after dividends on preferred stock	**$ 80.2**	**$ (4.8)**	$ (1.0)	$ 1.9

Operating Revenues

Details of the Company's operating revenues in 2010 and the prior two years were as follows:

	Amount		
	2010	2009	2008
		(in millions)	
Retail – prior year	**$ 790.9**	$ 785.4	$ 727.2
Estimated change in –			
Rates and pricing	**0.9**	0.6	18.8
Sales growth (decline)	**(2.9)**	(1.3)	(1.1)
Weather	**15.0**	1.7	(1.8)
Fuel and other cost recovery	**(6.0)**	4.5	42.3
Retail – current year	**797.9**	790.9	785.4
Wholesale revenues –			
Non-affiliates	**288.0**	299.3	353.8
Affiliates	**41.6**	44.5	100.9
Total wholesale revenues	**329.6**	343.8	454.7
Other operating revenues	**15.6**	14.7	16.4
Total operating revenues	**$1,143.1**	$1,149.4	$1,256.5
Percent change	**(0.6)%**	(8.5)%	12.8%

Total retail revenues for 2010 increased 0.9% when compared to 2009 primarily as a result of higher weather-driven energy sales, partially offset by lower fuel revenues. Total retail revenues for 2009 increased 0.7% when compared to 2008 primarily as a result of slightly higher energy sales and fuel revenues. Total retail revenues for 2008 increased 8.0% when compared to 2007 primarily as a result of a retail base rate increase effective in January 2008 and higher fuel revenues. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (or decline) and weather.

Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information. The fuel and other cost recovery revenues decreased in 2010 when compared to 2009 primarily as a result of lower recoverable fuel costs, partially offset by an increase in revenues related to ad valorem taxes. The fuel and other cost recovery revenues increased in 2009 when compared to 2008 primarily as a result of higher recoverable fuel costs. The fuel and other cost recovery revenues increased in 2008 when compared to 2007 primarily as a result of the increase in fuel and purchased power expenses. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel portion of wholesale revenues from energy sold to customers outside the Company's service territory.

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. Wholesale revenues from sales to non-affiliates decreased $11.4 million, or 3.8%, in 2010 as compared to 2009 as a result of an $11.8 million decrease in energy revenues, of which $9.5 million was associated with lower fuel prices and $2.3 million was associated with a decrease in kilowatt-hour (KWH) sales, partially offset by a $0.4 million increase in capacity revenues. Wholesale revenues from sales to non-affiliates decreased $54.5 million, or 15.4%, in 2009 as compared to 2008 as a result of a $54.1 million decrease in energy revenues, of which $27.6 million was associated with lower fuel prices and $26.4 million was associated with a decrease in KWH sales, and a $0.5 million decrease in capacity revenues. Wholesale revenues from sales to non-affiliates increased $30.7 million, or 9.5%, in 2008 as compared to 2007 as a result of a $30.4 million increase in energy revenues, of which $40.4 million was associated with higher fuel prices and a $0.3 million increase in capacity revenues, partially offset by a $10.0 million decrease in KWH sales.

Included in wholesale revenues from sales to non-affiliates are revenues from rural electric cooperative associations and municipalities located in southeastern Mississippi. The related revenues increased 4.2%, 1.5%, and 8.3% in 2010, 2009, and 2008, respectively. The 2010 increase was driven primarily by warmer weather in the second and third quarters 2010 and colder weather in the first and fourth quarters 2010 compared to the corresponding periods in 2009. The customer demand experienced by these utilities is determined by factors very similar to those experienced by the Company.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates (MBRs) that generally provide a margin above the Company's variable cost to produce the energy.

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 FERC.

Wholesale revenues from sales to affiliated companies decreased 6.6% in 2010 when compared to 2009, decreased 55.9% in 2009 when compared to 2008, and increased 118.6% in 2008 when compared to 2007. These energy sales do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues in 2010 increased $1.0 million, or 6.6%, from 2009 primarily due to an $0.8 million increase in rent from electric property. Other operating revenues in 2009 decreased $1.7 million, or 10.6%, from 2008 primarily due to a $1.0 million decrease in transmission revenues. Other operating revenues in 2008 decreased $0.9 million, or 5.0%, from 2007 primarily due to a sale of oil inventory and a customer contract buyout in 2007 totaling $0.9 million.

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 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	**2,296**	**9.8%**	(1.4)%	(0.6)%	**(0.3)%**	(2.1)%	(0.2)%
Commercial	**2,922**	**2.5**	(0.2)	(0.7)	**(2.1)**	(0.7)	0.5
Industrial	**4,466**	**3.2**	3.4	(3.0)	**3.2**	3.4	(3.0)
Other	**39**	**(0.7)**	-	0.3	**(0.7)**	-	0.3
Total retail	**9,723**	**4.4**	1.2	(1.7)	**0.7**	0.8	(1.3)
Wholesale							
Non-affiliated	**4,284**	**(7.9)**	(7.3)	(3.3)			
Affiliated	**774**	**(7.8)**	(43.6)	44.9			
Total wholesale	**5,058**	**(7.9)**	(15.6)	4.7			
Total energy sales	**14,781**	**(0.2)%**	(5.8)%	0.8%			

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 energy sales increased 9.8% in 2010 compared to 2009 due to warmer weather in the second and third quarters 2010 and colder weather in the first and fourth quarters 2010 compared to the corresponding periods in 2009. Residential energy sales decreased 1.4% in 2009 compared to 2008 due to the recessionary economy and a declining number of customers. Residential energy sales decreased 0.6% in 2008 compared to 2007 due to decreased customer usage mainly due to the recessionary economy and unfavorable summer weather.

Commercial energy sales increased 2.5% in 2010 compared to 2009 due to warmer weather in the second and third quarters 2010 and colder weather in the first and fourth quarters 2010 compared to the corresponding periods in 2009 and improving economic conditions. Commercial energy sales decreased 0.2% in 2009 compared to 2008 due to the recessionary economy and a net decline in commercial customers. Commercial energy sales decreased 0.7% in 2008 compared to 2007 due to unfavorable weather and slower than expected customer growth due to the economy.

Industrial energy sales increased 3.2% in 2010 compared to 2009 due to a return to more normal production levels for most of the Company's industrial customers from an improving economy. Industrial energy sales increased 3.4% in 2009 compared to 2008 due to increased production of some of the Company's industrial customers and the impacts of Hurricane Gustav, which negatively impacted industrial energy sales in 2008. Industrial energy sales decreased 3.0% in 2008 compared to 2007 due to lower customer use from the recessionary economy.

Wholesale energy sales to non-affiliates decreased 7.9%, 7.3%, and 3.3% in 2010, 2009, and 2008, respectively. Included in wholesale sales to non-affiliates are sales to rural electric cooperative associations and municipalities located in southeastern Mississippi. Compared to the prior year, KWH sales to these customers increased 9.2% in 2010 due to warmer weather in the second and third quarters 2010 and colder weather in the first and fourth quarters 2010 compared to the corresponding periods in 2009, remained at the same levels in 2009 despite the recessionary economy and unfavorable weather, and decreased 0.9% in 2008 due to slowing growth and unfavorable weather. KWH sales to non-territorial customers located outside the Company's service territory decreased 79.8% in 2010 as compared to 2009 primarily due to fewer short-term opportunity sales related to lower gas prices. KWH sales to non-territorial customers located outside the Company's service territory decreased 29.0% in 2009 as compared to 2008 primarily due to fewer short-term opportunity sales related to lower gas prices. KWH sales to non-territorial customers located outside the Company's service territory decreased 9.6% in 2008 as compared to 2007 primarily due to lower off-system sales. Wholesale 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.

Wholesale energy sales to affiliates decreased 7.8% in 2010 as compared to 2009 primarily due to an increase in the Company's generation and an increase in territorial sales, resulting in less capacity available to sell to affiliate companies. Wholesale energy sales to affiliates decreased 43.6% in 2009 as compared to 2008 primarily due to a decrease in the Company's generation and an increase in territorial sales, resulting in less capacity available to sell to affiliate companies. Wholesale energy sales to affiliates increased 44.9% in 2008 as compared to 2007 primarily due to the availability of the Company's lower cost generation resources for sale to 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)*	**13,146**	12,970	14,324
Total purchased power *(millions of KWHs)*	**2,330**	2,539	2,091
Sources of generation *(percent)* –			
Coal	**51**	48	67
Gas	**49**	52	33
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**4.08**	4.29	3.52
Gas	**4.22**	4.43	6.83
Average cost of fuel, generated *(cents per net KWH)*	**4.14**	4.36	4.43
Average cost of purchased power *(cents per net KWH)*	**3.59**	3.62	6.05

Fuel and purchased power expenses were $585.5 million in 2010, a decrease of $26.1 million, or 4.3%, below the prior year costs. This decrease was primarily due to a $26.6 million decrease in the cost of fuel and purchased power, partially offset by a $0.5 million increase related to total KWHs generated and purchased. Fuel and purchased power expenses were $611.6 million in 2009, a decrease of $101.4 million, or 14.2%, below the prior year costs. This decrease was primarily due to a $69.9 million decrease in the cost of fuel and purchased power and a $31.5 million decrease related to total KWHs generated and purchased. Fuel and purchased power expenses were $713.1 million in 2008, an increase of $122.9 million, or 20.8%, above the prior year costs. This increase was primarily due to a $116.5 million increase in the cost of fuel and purchased power and a $6.4 million increase related to total KWHs generated and purchased.

Fuel expense decreased $17.8 million in 2010 as compared to 2009. Approximately $25.8 million of the reduction in fuel expenses resulted primarily from lower fuel prices, partially offset by an $8.0 million increase in generation from Company-owned facilities. Fuel expense decreased $66.8 million in 2009 as compared to 2008. Approximately $8.1 million of the reduction in fuel expenses resulted primarily from lower gas prices and a $58.7 million decrease in generation from Company-owned facilities. Fuel expense increased $92.2 million in 2008 as compared to 2007. Approximately $86.1 million in additional fuel expenses resulted from higher coal, gas, and transportation prices and a $6.1 million increase in generation from Company-owned facilities.

Purchased power expense decreased $8.3 million, or 9.0%, in 2010 when compared to 2009. The decrease was primarily due to a $0.7 million decrease in the cost of purchased power and a $7.6 million decrease in the amount of energy purchased resulting from higher cost opportunity purchases. Purchased power expense decreased $34.6 million, or 27.4%, in 2009 when compared to 2008. The decrease was primarily due to a $61.8 million decrease in the cost of purchased power, partially offset by a $27.2 million increase in the amount of energy purchased which was due to lower cost opportunity purchases. Purchased power expense increased $30.7 million, or 32.0%, in 2008 when compared to 2007. The increase was primarily due to a $30.4 million increase in the cost of purchased power. Energy purchases vary from year to year depending on demand and the availability and cost of the Company's generating resources. These expenses do not have a significant impact on earnings since the energy purchases are generally offset by energy revenues through the Company's fuel cost recovery clause.

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 clause. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" and Note 1 to the financial statements under "Fuel Costs" for additional information.

Other Operations and Maintenance Expenses

Total other operations and maintenance expenses increased $21.3 million in 2010 as compared to 2009 primarily due to an $8.5 million increase in generation maintenance expenses for several major planned outages, a $4.2 million increase in transmission and distribution expenses related to substation and overhead line maintenance and vegetation management costs, a $4.6 million increase in administrative and general expenses, and a $5.6 million increase in labor costs.

Total other operations and maintenance expenses decreased $13.3 million in 2009 as compared to 2008 primarily due to a decrease of $12.2 million in transmission, distribution, customer service, and administrative and general expenses driven by overall reductions in spending in an effort to offset the effects of the recessionary economy. Also contributing to the decrease was an $8.3 million reduction in generation outage expenses in 2009. These decreases were partially offset by a $3.9 million increase in expenses for the combined cycle long-term service agreement due to a 36% increase in operating hours as a result of lower gas prices. Also offsetting the decrease was $3.4 million resulting from the 2008 reclassification of generation construction screening expenses to a regulatory asset upon the FERC's acceptance of the wholesale base rate increase effective in January 2009.

Total other operations and maintenance expenses increased $4.8 million in 2008 as compared to 2007 primarily due to a $6.9 million increase in transmission and distribution expenses, an increase in administrative expenses primarily resulting from the reclassification of System Restoration Rider (SRR) revenues of $3.8 million to expense pursuant to a January 2009 order from the Mississippi PSC, a $1.9 million increase in generation-related environmental expenses, and a $1.1 million increase in generation operations and outage-related expenses. These increases were partially offset by a $9.3 million reclassification of generation construction screening expenses to a regulatory asset upon the FERC's acceptance of the wholesale base rate increase effective in January 2009.

See FUTURE EARNINGS POTENTIAL – "PSC Matters – System Restoration Rider," and Note 3 to the financial statements under "Retail Regulatory Matters – Storm Damage Cost Recovery" for additional information.

Depreciation and Amortization

Depreciation and amortization increased $6.0 million in 2010 compared to 2009 primarily due to a $2.9 million increase in amortization of environmental costs related to the approved Environmental Compliance Overview (ECO) Plan and a $2.7 million increase in depreciation primarily resulting from an increase in plant in service. Depreciation and amortization decreased $0.1 million in 2009 compared to 2008 primarily due to a $3.1 million decrease in amortization of environmental costs related to the approved ECO Plan, partially offset by a $2.8 million increase in depreciation resulting from an increase in plant in service. Depreciation and amortization increased $10.7 million in 2008 compared to 2007 primarily due to a $5.7 million increase in amortization related to a regulatory liability recorded in 2003 that ended in December 2007 in connection with the Mississippi PSC's accounting order on Plant Daniel capacity, a $2.9 million increase in depreciation primarily due to an increase in plant in service, and a $2.4 million increase for amortization of certain reliability-related maintenance costs deferred in 2007 in accordance with a Mississippi PSC order. See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" and "Environmental Compliance Overview Plan" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $5.7 million in 2010 compared to 2009 primarily as a result of a $5.5 million increase in ad valorem taxes and a $0.2 million increase in payroll taxes. Taxes other than income taxes decreased $1.0 million in 2009 compared to 2008 primarily as a result of an $0.8 million decrease in payroll taxes and a $0.2 million decrease in franchise taxes. Taxes other than income taxes increased $4.8 million in 2008 compared to 2007 primarily as a result of a $2.7 million increase in ad valorem taxes and a $1.3 million increase in municipal franchise taxes.

Allowance for Equity Funds Used During Construction

Allowance for funds used during construction (AFUDC) equity increased $3.4 million in 2010 as compared to 2009. This increase was primarily due to increases in construction of the Kemper IGCC. The AFUDC equity change for 2009 as compared to 2008 was immaterial. The increase of $0.6 million in 2008 as compared to 2007 was primarily related to the Plant Watson cooling tower project. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Interest Income

Interest income decreased $0.6 million in 2010 as compared to 2009 primarily due to lower interest income related to a regulatory recovery mechanism for fuel and energy cost hedging. Interest income decreased $1.2 million in 2009 as compared to 2008 primarily due to lower interest income related to a regulatory recovery mechanism for fuel and energy cost hedging. The interest income change for 2008 as compared to 2007 was immaterial.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $0.6 million in 2010 compared to 2009 primarily due to a $2.8 million increase in AFUDC debt associated with the Kemper IGCC, partially offset by an increase in interest expense associated with the issuances of new long-term debt in September and December 2010. Interest expense, net of amounts capitalized increased $5.0 million in 2009 compared to 2008 primarily due to a $5.2 million increase in interest expense associated with the issuances of new long-term debt in November 2008 and March 2009, partially offset by the maturity of long-term debt and lower interest rates in 2009. Interest expense, net of amounts capitalized decreased $0.2 million in 2008 compared to 2007 primarily due to a $2.7 million decrease in borrowing and lower interest rates on short-term indebtedness and a $0.7 million decrease related to the redemption of outstanding trust preferred securities in 2007, partially offset by a $3.0 million increase in interest expense associated with the issuances of new long-term debt in November 2008 and November 2007.

Other Income (Expense), Net

Other income (expense), net increased $1.1 million in 2010 compared to 2009 primarily due to a $1.4 million increase in amounts collected from customers for contributions in aid of construction, partially offset by a $0.2 million decrease resulting from mark-to-market losses on energy-related derivative positions. Other income (expense), net decreased $1.5 million in 2009 compared to 2008 primarily due to a $3.0 million decrease in customer projects and amounts collected from customers for construction of substation projects which had a tax effect of $2.6 million, partially offset by higher charitable contributions of $3.9 million in 2008. Other income (expense), net decreased $1.9 million in 2008 compared to 2007 primarily due to higher charitable contributions of $3.1 million, partially offset by a $0.4 million increase in revenues from contracting work performed for customers and a $0.6 million decrease in other deductions.

Income Taxes

Income taxes decreased $3.9 million, or 7.8%, in 2010 compared to 2009 primarily due to decreased pre-tax income, a decrease in unrecognized tax benefits, and an increase in AFUDC equity, which is non-taxable, partially offset by a decrease in the federal production activities deduction and a decrease in a State of Mississippi manufacturing investment tax credit. Income taxes increased $1.9 million, or 3.9%, in 2009 compared to 2008 primarily due to increased pre-tax income, the 2008 amortization of a regulatory liability pursuant to a December 2007 regulatory accounting order from the Mississippi PSC which occurred in 2008, and actualization of permanent differences from previous year tax returns, partially offset by an increase in the federal production activities deduction and an increase in a State of Mississippi manufacturing investment tax credit. Income taxes decreased $3.4 million, or 6.7%, in 2008 compared to 2007 primarily due to decreased pre-tax income, the amortization of a regulatory liability pursuant to a December 2007 regulatory accounting order from the Mississippi PSC, and a State of Mississippi manufacturing investment tax credit, partially offset by a decrease in the federal production activities deduction. See Note 3 to the financial statements under "Retail Regulatory Matters" 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 southeast Mississippi and to wholesale customers in the southeast U.S. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. See "FERC Matters" herein, ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein, and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

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

Environmental Matters

Compliance costs related to 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 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 to the Company with respect to the Company's Plant Watson. 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. In early 2000, the EPA filed a motion to amend its complaint to add the Company as a defendant based on the allegations in the notices of violation. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not re-filed. The original action, now solely against Georgia Power, has been administratively closed since the spring of 2001, and the case has not been reopened. The separate action against Alabama Power is ongoing.

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, including the claim relating to the facility co-owned by the Company. 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 \$226 million in environmental capital projects to comply with these requirements, with annual totals of \$2 million, \$22 million, and \$41 million for 2010, 2009, and 2008, respectively. The Company expects that capital expenditures to comply with existing statutes and regulations will be \$45 million, \$94 million, and \$127 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 \$0 in 2011, up to \$18 million in 2012, and up to \$55 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.

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 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 \$109 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 nonattainment areas within the Company's service territory and could result in additional required reductions in NO_x emissions.

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 Mississippi and Alabama, 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 Mississippi and Alabama 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 Alabama, 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 Alabama 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 any of 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, 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 at certain facilities within the next several years to ensure continued compliance with applicable air quality requirements. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

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.

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. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Coal Combustion Byproducts

The Company currently operates two electric generating plants with on-site coal combustion byproduct storage facilities (with both "wet" (ash ponds) and "dry" (landfill) storage facilities). In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse (approximately 40% in recent years). Historically, individual states have regulated coal combustion byproducts and the states in Southern Company's service territory, including the States of Mississippi and Alabama, 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 10 million metric tons. The preliminary estimate of carbon dioxide emissions from these units in 2010 is approximately 10 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 is actively evaluating and developing electric generating technologies with lower greenhouse gas emissions. This includes construction of the Kemper IGCC facility with approximately 65% carbon capture.

FERC Matters

In October 2010, the Company filed a request with the FERC for a revised wholesale electric tariff and revised rates. Prior to making this filing, the Company reached a settlement with all of its customers who take service under the tariff. This settlement agreement was filed with the FERC as part of the request. The settlement agreement provided for an increase in annual base wholesale revenues in the amount of $4.1 million, effective January 1, 2011. In addition, the settlement agreement allows the Company to implement an emissions allowance cost clause, effective January 1, 2011. The emissions allowance cost clause contains an over and under recovery provision similar to the fuel recovery clause and is projected to collect $6.9 million in 2011. The settlement agreement also provided for collection of $2.8 million of 2010 emissions allowance expense for the period of September 1, 2010 through December 31, 2010 and allows the Company to defer the wholesale portion of the income tax expense associated with the change in taxability of the federal subsidy under the Patient Protection and Affordable Care Act (PPACA) and the Health Care and Education Reconciliation Act of 2010 (together with PPACA, the Acts). On December 7, 2010, the Company received notice that the FERC had accepted the filing effective December 21, 2010. As a result of the FERC acceptance, the $2.8 million of emission allowance revenue is included in the statements of income for 2010. Beginning January 1, 2011, the Company implemented the wholesale emissions allowance cost clause and revised monthly charges for the increase in annual base wholesale revenues.

PSC Matters

Mississippi Baseload Construction Legislation

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor in May 2008 to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. The effect of this legislation on the Company cannot now be determined. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information on the application of the Baseload Act to the Kemper County IGCC facility.

Performance Evaluation Plan

In the May 2004 order establishing the Company's forward-looking PEP, the Mississippi PSC ordered that the Mississippi Public Utilities Staff and the Company review the operations of the PEP in 2007. By mutual agreement, this review was deferred until 2008 and continued into 2009. In March 2009, concurrent with this review, the annual PEP evaluation filing for 2009 was suspended. In August 2009, the Mississippi Public Utilities Staff and the Company filed a joint report with the Mississippi PSC proposing several changes to the PEP. In November 2009, the Mississippi PSC approved the revised PEP, which resulted in a lower performance incentive under the PEP and therefore smaller and/or less frequent rate changes in the future. In November 2009, the Company resumed annual evaluations and filed its annual PEP filing for 2010 under the revised PEP, which resulted in a lower allowed return on investment but no rate change. On November 15, 2010, the Company filed its annual PEP filing for 2011 under the revised PEP, which indicated a rate increase of 1.936%, or $16.1 million, annually. On January 10, 2011, the Mississippi Public Utilities Staff contested the filing. Under the revised PEP, the review of the annual PEP filing must be concluded by the first billing cycle in April. The ultimate outcome of this matter cannot be determined at this time.

In April 2007, the Mississippi PSC issued an order allowing the Company to defer certain reliability related maintenance costs beginning January 1, 2007 and recover them evenly over a four-year period beginning January 1, 2008. These costs related to maintenance that was needed as follow-up to emergency repairs that were made subsequent to Hurricane Katrina. At December 31, 2007, the Company had incurred and deferred the retail portion of $9.5 million of such costs. At December 31, 2010, the Company had a balance of the deferred retail portion of $2.4 million included in current assets as other regulatory assets. See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

On March 15, 2010, the Company submitted its annual PEP lookback filing for 2009, which recommended no surcharge or refund. On October 26, 2010, the Company and the Mississippi Public Utilities Staff agreed and stipulated that no surcharge or refund is required. On November 2, 2010, the Mississippi PSC accepted the stipulation. On or before March 15, 2011, the Company will submit its annual PEP lookback filing for 2010. The ultimate outcome of this matter cannot be determined at this time.

System Restoration Rider

The Company is required to make annual SRR filings to determine the revenue requirement associated with the property damage. The purpose of the SRR is to provide for recovery of costs associated with property damage (including certain property insurance and the costs of self insurance) and to facilitate the Mississippi PSC's review of these costs. The Mississippi PSC periodically agrees on SRR revenue levels that are developed based on historical data, expected exposure, type and amount of insurance coverage excluding insurance costs, and other relevant information. The applicable SRR rate level will be adjusted every three years, unless a significant change in circumstances occurs such that the Company and the Mississippi Public Utilities Staff or the Mississippi PSC deems that a more frequent change would be appropriate. The Company will submit annual filings setting forth SRR-related revenues, expenses, and investment for the projected filing period, as well as the true-up for the prior period. As a result of the Mississippi PSC establishing the current SRR calculation in January 2009, the December 2008 retail regulatory liability of $6.8 million was reclassified to the property damage reserve.

In February 2009, the Company submitted its 2009 SRR rate filing with the Mississippi PSC, which proposed that the 2009 SRR rate level remain at zero and the Company be allowed to accrue approximately $4.0 million to the property damage reserve in 2009. In September 2009, the Mississippi PSC issued an order requiring the Company to develop SRR factors designed to reduce SRR revenue by approximately $1.5 million from November 2009 to March 2010 under the new rate. On January 29, 2010, the Company submitted its 2010 SRR rate filing with the Mississippi PSC, which allowed the Company to accrue $3.1 million to the property damage reserve in 2010. On January 31, 2011, the Company submitted its 2011 SRR rate filing with the Mississippi PSC, which proposed that the Company be allowed to accrue approximately $3.6 million to the property damage reserve in 2011. The ultimate outcome of this matter cannot be determined at this time.

Environmental Compliance Overview Plan

On February 14, 2011, the Company submitted its 2011 ECO Plan notice which proposed an immaterial decrease in annual revenues for the Company. In addition, the Company proposed to change the ECO Plan collection period to more appropriately match ECO revenues with ECO expenditures. The ultimate outcome of this matter cannot be determined at this time.

On February 12, 2010, the Company submitted its 2010 ECO Plan notice which proposed an increase in annual revenues for the Company of approximately $3.9 million. Due to changes in ECO Plan cost projections, on August 20, 2010, the Company submitted a revised 2010 ECO Plan which reduced the requested increase in annual revenues to $1.7 million. In its 2010 ECO Plan filing, the Company proposed to change the true-up provision of the ECO Plan rate schedule to consider actual revenues collected in addition to actual costs. Hearings on the 2010 ECO Plan were held with the Mississippi PSC on October 5, 2010. On October 25, 2010, the Mississippi PSC held a public meeting to discuss the 2010 ECO Plan and issued an order approving the revised 2010 ECO Plan with the new rates effective in November 2010. The Company and the Mississippi Public Utilities Staff jointly agreed to defer the decision on the change in the true-up provision of the ECO Plan rate schedule. As a result of the change in the collection period requested in the Company's 2011 ECO filing, the Company has decided not to pursue the change in the true-up provision.

In February 2009, the Company submitted its 2009 ECO Plan notice which proposed an increase in annual revenues for the Company of approximately $1.5 million. In June 2009, the Mississippi PSC approved the ECO Plan with the new rates effective in June 2009.

On July 22, 2010, the Company 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 the Company and Gulf Power, 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 Mississippi PSC, is expected to be recovered through the ECO Plan. Hearings on the certificate request were held by the Mississippi PSC on January 25, 2011 with a final order expected by February 28, 2011. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; such filing occurred on November 15, 2010. The Mississippi PSC approved the retail fuel cost recovery factor on December 7, 2010, with the new rates effective in January 2011. The retail fuel cost recovery factor will result in an annual decrease in an amount equal to 5.0% of total 2010 retail revenue. At December 31, 2010, the amount of over recovered retail fuel costs included in the balance sheets was $55.2 million compared to $29.4 million at December 31, 2009. The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2011, the wholesale MRA fuel rate decreased, resulting in an annual decrease in an amount equal to 3.5% of total 2010 MRA revenue. Effective February 1, 2011, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 7.0% of total 2010 MB revenue. At December 31, 2010, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $17.5 million and $4.4 million compared to $16.8 million and $2.4 million, respectively, at December 31, 2009. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, this decrease to the billing factor will have no significant effect on the Company's revenues or net income, but will decrease annual cash flow.

In October 2010, the Mississippi PSC engaged an independent professional audit firm to conduct an audit of the Company's fuel-related expenditures included in the retail fuel adjustment clause and energy cost management clause (ECM) for 2010. The audit is scheduled to be completed in 2011. The ultimate outcome of this matter cannot be determined at this time. A similar audit was conducted beginning in August 2009 for the years 2009 and 2008. The audit was completed in December 2009 with no audit findings.

In October 2008, the Mississippi PSC opened a docket to investigate and review interest and carrying charges under the fuel adjustment clause for utilities within the State of Mississippi including the Company. In March 2009, the Mississippi PSC issued an order to apply the prime rate in calculating the carrying costs on the retail over or under recovery balances related to fuel cost recovery. In May 2009, the Company filed the carrying cost calculation methodology as part of its compliance filing.

Legislation

Stimulus Funding

On April 28, 2010, Southern Company signed a Smart Grid Investment Grant agreement with the U.S. Department of Energy (DOE), 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, $25.9 million under this agreement. The ultimate outcome of this matter cannot be determined at this time.

Healthcare Reform

On March 23, 2010, the PPACA was signed into law and, on March 30, 2010, 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 $4.7 million for the Company. Although Internal Revenue Service (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 $28 million in increased cash flow. The Company estimates the potential increased cash flow for 2011 to be between approximately $20 million and $25 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 (Internal Revenue Code). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is 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.

Integrated Coal Gasification Combined Cycle

In January 2009, the Company filed for a Certificate of Public Convenience and Necessity (CPCN) with the Mississippi PSC to allow the acquisition, construction, and operation of the IGCC project located in Kemper County, Mississippi. The Kemper IGCC would utilize an IGCC technology with an output capacity of 582 megawatts (MWs). The estimated cost of the plant is $2.4 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (CCPI2). The plant will use locally mined lignite (an abundant, lower heating value coal) from a proposed mine adjacent to the plant as fuel. In conjunction with the plant, the Company will own a lignite mine and equipment and will acquire mineral reserves located around the plant site in Kemper County. The estimated capital cost of the mine is approximately $214 million. On May 27, 2010, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC, a subsidiary of The North American Coal Corporation, which will develop, construct, and manage the mining operations. The agreement is effective June 1, 2010 through the end of the mine reclamation. The plant, subject to federal and state reviews and certain regulatory approvals, is expected to begin commercial operation in May 2014. As part of its filing, the Company requested certain rate recovery treatment in accordance with the Baseload Act.

Beginning in December 2006, the Mississippi PSC approved the Company's requested accounting treatment to defer the costs associated with the Company's generation resource planning, evaluation, and screening activities as a regulatory asset. In April 2009, the Company received an accounting order from the Mississippi PSC directing the Company to continue to charge all generation resource planning, evaluation, and screening costs to regulatory assets including those costs associated with activities to obtain a CPCN and costs necessary and prudent to preserve the availability, economic viability, and/or required schedule of the Kemper IGCC generation resource planning, evaluation, and screening activities until the Mississippi PSC makes findings and determination as to the recovery of the Company's prudent expenditures.

In June 2009, the Mississippi PSC issued an order initiating an evaluation of the Company's CPCN petition and established a two-phase procedural schedule to evaluate the need for and the resources and cost of the new generating capacity separately. In November 2009, the Mississippi PSC issued an order that found the Company had demonstrated a need for additional capacity of approximately 304 MWs to 1,276 MWs based on an analysis of expected load forecasts, costs, and anticipated retirements. Hearings related to the appropriate resource to meet that need as well as cost recovery of that resource through application of the Baseload Act were held in February 2010.

On April 29, 2010, the Mississippi PSC issued an order finding that the Company's application to acquire, construct, and operate the plant did not satisfy the requirement of public convenience and necessity in the form that the project and the related cost recovery were originally proposed by the Company, unless the Company accepted certain conditions on the issuance of the CPCN, including a cost cap of approximately $2.4 billion. The April 2010 order also approved recovery of $46 million out of $50.5 million in prudent pre-construction costs incurred through March 2009. The remaining $4.5 million is associated with overhead costs and variable pay of Southern Company Services, Inc., which were recommended for exclusion from pre-construction costs by a consultant hired by the Mississippi Public Utilities Staff. An additional $3.5 million was incurred for costs of this type from March 2009 through May 2010. The remaining $4.5 million, as well as additional pre-construction amounts incurred during the generation screening and evaluation process through May 2010, will be reviewed and addressed in a future proceeding.

On May 10, 2010, the Company filed a motion in response to the April 29, 2010 order of the Mississippi PSC relating to the Kemper IGCC, or in the alternative, for alteration or rehearing of such order.

On May 26, 2010, the Mississippi PSC issued an order revising its findings from the April 29, 2010 order. Among other things, the Mississippi PSC's May 26, 2010 order (1) approved an alternate construction cost cap of up to $2.88 billion (and any amounts that fall within specified exemptions from the cost cap; such exemptions include the costs of the lignite mine and equipment and the carbon dioxide pipeline facilities), subject to determinations by the Mississippi PSC that such costs in excess of $2.4 billion are prudent and required by the public convenience and necessity; (2) provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's proposal; and (3) approved financing cost recovery on construction work in progress (CWIP) balances under the Baseload Act, which provides for the accrual of AFUDC in 2010 and 2011 and recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of CWIP allowed is (i) reduced by the amount of state and federal government construction cost incentives received by the Company in excess of $296 million to the extent that such amount increases cash flow for the pertinent regulatory period and (ii) justified by a showing that such CWIP allowance will benefit customers over the life of the plant). The Mississippi PSC order established periodic prudence reviews during the annual CWIP review process. More frequent prudence determinations may be requested at a later time. On May 27, 2010, the Company filed a motion with the Mississippi PSC accepting the conditions contained in the order. On June 3, 2010, the Mississippi PSC issued the final certificate order which granted the Company's motion and issued the CPCN authorizing acquisition, construction, and operation of the plant. As of May 31, 2010, construction related screening costs of $116.2 million were reclassified to CWIP while the non-capital related costs of $11.2 million and $0.6 million were classified in other regulatory assets and other deferred charges, respectively, and $1.0 million was previously expensed.

Pursuant to the Mississippi PSC's order granting the CPCN for the Kemper IGCC, the Mississippi PSC and Mississippi Public Utilities Staff has hired various consultants to assist both organizations in monitoring the construction of the plant.

On June 17, 2010, the Mississippi Chapter of the Sierra Club (Sierra Club) filed an appeal of the Mississippi PSC's June 3, 2010 decision to grant the CPCN for the plant with the Chancery Court of Harrison County, Mississippi (Chancery Court). Subsequently, on July 6, 2010, the Sierra Club also filed an appeal directly with the Mississippi Supreme Court. On July 20, 2010, the Chancery Court issued a stay of the proceeding pending the resolution of the jurisdictional issues raised in a motion filed by the Company on July 16, 2010 to confirm jurisdiction in the Mississippi Supreme Court. On October 7, 2010, the Mississippi Supreme Court denied the Company's motion and dismissed the Sierra Club's direct appeal. The appeal will now proceed in the Chancery Court. On

December 22, 2010, the Chancery Court denied the Company's motion to dismiss. A decision on the Sierra Club's appeal from the Chancery court is expected in March 2011.

On November 12, 2010, the Company filed a petition with the Mississippi PSC requesting an accounting order that would establish regulatory assets for certain non-capital costs related to the Kemper IGCC. In its petition, the Company outlined three categories of non-capital, plant-related costs that it proposed to defer in a regulatory asset until construction is complete and a cost recovery mechanism is established for the plant: (1) regulatory costs; (2) costs of executing non-construction contracts; and (3) other project-related costs not permitted to be capitalized.

The Company filed an application in June 2006 with the DOE for certain tax credits available to projects using clean coal technologies under the Energy Policy Act of 2005. The DOE subsequently certified the plant, and in November 2006, the IRS allocated Internal Revenue Code Section 48A tax credits (Phase I) of $133 million to the Company. In May 2009, the Company received notification from the IRS formally certifying these tax credits. In addition, the Company filed an application in November 2009 with the DOE and in December 2009 with the IRS for certain tax credits (Phase II) available to projects using advanced coal technologies under the Energy Improvement and Extension Act of 2008. The DOE subsequently certified the Kemper IGCC, and on April 30, 2010, the IRS allocated $279 million of Phase II tax credits under Section 48A of the Internal Revenue Code to the Company. On September 30, 2010, the Company and the IRS executed the closing agreement for the Phase II tax credits. The Company has secured all environmental reviews and permits necessary to commence construction of the plant and has entered into a binding contract for the steam turbine generator, completing two milestone requirements for these credits. The utilization of Phase I and Phase II credits are dependent upon meeting the IRS certification requirements, including an in-service date no later than May 2014 for the Phase I credits. In order to remain eligible for the Phase II tax credits, the Company plans to capture and sequester (via enhanced oil recovery) at least 65% of the carbon dioxide produced by the plant during operations in accordance with the recapture rules for Section 48A investment tax credits. Through December 31, 2010, the Company received tax benefits of $21.9 million for these tax credits.

In February 2008, the Company requested that the DOE transfer the remaining funds previously granted under the CCPI2 from a cancelled IGCC project of one of Southern Company's subsidiaries that would have been located in Orlando, Florida. In December 2008, an agreement was reached to assign the remaining funds ($270 million) to the Kemper IGCC. On August 19, 2010, the National Environmental Policy Act (NEPA) Record of Decision (ROD) by the DOE for the CCPI2 grants was noted in the Federal Register. The NEPA ROD and its accompanying final environmental impact statement were the final major hurdles necessary for the Company to receive grant funds of $245 million during the construction of the plant and $25 million during the initial operation of the plant. As of December 31, 2010, the Company has received $23.1 million and billed an additional $9.5 million associated with this grant.

On July 27, 2010, the Company and South Mississippi Electric Power Association (SMEPA) entered into an Asset Purchase Agreement whereby SMEPA will purchase an undivided 17.5% interest in the plant. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. On December 2, 2010, the Company and SMEPA filed a Joint Petition with the Mississippi PSC requesting regulatory approval for SMEPA's 17.5% ownership of the Kemper IGCC.

On March 9, 2010, the Mississippi Department of Environmental Quality issued the PSD air permit modification for the plant, which modifies the original PSD air permit issued in October 2008. The Sierra Club has requested a formal evidentiary hearing regarding the issuance of the modified permit.

On November 18, 2010, the U.S. Army Corps of Engineers issued the Section 404 wetlands permit for the generating facility. On December 10, 2010, the U.S. Army Corps of Engineers issued the same permit for the Liberty Fuels Lignite Mine.

As of December 31, 2010, the Company had spent a total of $255.1 million on the plant, including regulatory filing costs. Of this total, $207.6 million was included in CWIP (net of $32.7 million of CCPI2 grant funds), $12.3 million was recorded in other regulatory assets, $1.5 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed.

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

Other Matters

In February 2008, the Company received notice of termination from SMEPA of an approximately 100 MW territorial wholesale market-based contract effective March 31, 2011 which will result in a decrease in annual base revenues of approximately $12 million. In December 2008, the Company entered into a 10-year power supply agreement with SMEPA for approximately 152 MWs. This contract is effective April 1, 2011. This contract is expected to increase the Company's annual territorial wholesale base revenues by approximately $16.1 million. In September 2010, SMEPA executed a 10-year Network Integration Transmission Service Agreement with Southern Company. Service will begin on April 1, 2011. The estimated Open Access Transmission Tariff revenue over the life of the contract is approximately $39.3 million with the Company's share being $29.3 million.

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 Mississippi 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.

Plant Daniel Operating Lease

As discussed in Note 7 to the financial statements under "Operating Leases – Plant Daniel Combined Cycle Generating Units," the Company leases a 1,064-MW natural gas combined cycle facility at Plant Daniel (Facility) from Juniper Capital L.P. (Juniper). For both accounting and rate recovery purposes, this transaction is treated as an operating lease, which means that the related obligations under this agreement are not reflected in the balance sheets. See FINANCIAL CONDITION AND LIQUIDITY – "Off-Balance Sheet Financing Arrangements"herein for further information. The operating lease determination was based on assumptions and estimates related to the following:

- Fair market value of the Facility at lease inception;
- The Company's incremental borrowing rate;
- Timing of debt payments and the related amortization of the initial acquisition cost during the initial lease term;
- Residual value of the Facility at the end of the lease term;
- Estimated economic life of the Facility; and
- Juniper's status as a voting interest entity.

The determination of operating lease treatment was made at the inception of the lease agreement and is not subject to change unless subsequent changes are made to the agreement. However, the Company is also required to monitor Juniper's ongoing status as a voting interest entity. Changes in that status could require the Company to consolidate the Facility's assets and the related debt and to record interest expense and depreciation of approximately $37 million annually, rather than annual lease expense of approximately $26 million.

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 $1.3 million or less change in the total benefit expense and a $14 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 $42.9 million to the qualified pension plan.

Net cash provided from operating activities totaled $132.7 million in 2010 compared to $170.6 million for 2009. The $38.0 million decrease in net cash provided from operating activities was primarily due to a $42.9 million cash payment to fund the qualified pension plan, an increase in spending related to the Kemper IGCC generation construction screening costs of $19.9 million, and a decrease in cash received related to lower fuel rates effective in the first quarter 2010. These decreases in cash are partially offset by an increase in deferred income taxes of $77.4 million primarily related to a long-term service agreement (LTSA), bonus depreciation, and an increase in investment tax credits of $22.2 million related to the Kemper IGCC. Net cash provided from operating activities in 2009 increased from 2008 by $76.2 million. The increase in net cash provided from operating activities was primarily due to an increase in cash related to higher fuel rates effective in March 2009 and a decrease in deferred income taxes. Net cash provided from operating activities in 2008 decreased from 2007 by $112.2 million. The decrease in net cash provided from operating activities was primarily due to the receipt of grant proceeds of $74.3 million in June 2007 and a decrease in operating activities related to receivables in 2008 in the amount of $49.5 million. The decrease in receivables is primarily due to the change in under recovered regulatory clause revenues of $24.7 million and a $24.1 million change in affiliate receivables. Also impacting operating activities were decreases related to fossil fuel stock of $33.3 million primarily due to increases in coal and coal in-transit of $22.0 million and $15.6 million, respectively. These were offset by an increase in deferred income taxes and investment tax credits of $61.4 million.

Net cash used for investing activities totaled $254.4 million for 2010 compared to $119.4 million for 2009. The $135.0 million increase was primarily due to an increase in property additions of $145.0 million primarily related to the Kemper IGCC and an increase in investment in restricted cash of $50.0 million, partially offset by capital grant proceeds of $23.7 million related to CCPI2 and the Smart Grid Investment grant and $33.8 million in construction payables. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and "Legislation" herein for additional information. Net cash used for investing activities totaled $119.4 million for 2009 compared to $155.8 million for 2008. The $36.4 million decrease was primarily due to a decrease in property additions. The $55.3 million increase in net cash used for investing activities in 2008 was primarily due to a

$12.1 million increase in construction payables and a $27.6 million increase due to the capital portion of Hurricane Katrina grant proceeds received in 2007.

Net cash provided from financing activities totaled $217.5 million in 2010 compared to net cash used for financing activities of $8.6 million in 2009. The $226.1 million increase was primarily due to a $100.0 million increase in long-term debt at December 31, 2010, a $60.6 million increase in capital contributions from Southern Company, and a $40.0 million redemption of long-term debt in the third quarter 2009. Net cash used for financing activities totaled $8.6 million in 2009 compared to $78.9 million that was provided from financing activities in 2008. The $87.5 million decrease was primarily due to a $42.6 million decrease in notes payable and a $40 million decrease in long-term debt as a result of a March 2009 senior note redemption, when compared to the corresponding period in 2008. Net cash provided from financing activities totaled $78.9 million in 2008 compared to $105.5 million that was used in financing activities for the corresponding period in 2007. The $184.5 million increase in net cash provided from financing activities was primarily due to the $80 million long-term bank loan issued to the Company in March 2008, the $50 million senior notes issued in November 2008, and the $36 million redemption of the long-term debt to an affiliated trust in the first nine months of 2007. Notes payable increased by $57.8 million primarily due to additional borrowings from commercial paper.

Significant changes in the balance sheet as of December 31, 2010 compared to 2009 include an increase in cash and cash equivalents of $95.8 million resulting from bond proceeds and a capital contribution from Southern Company in December 2010. Restricted cash increased $50.0 million primarily due to the issuance of the second series of revenue bonds. The second series revenue bonds were redeemed on February 8, 2011. Total property, plant, and equipment increased $281.2 million primarily due to the increase in CWIP related to the Kemper IGCC. Upon the Mississippi PSC issuance of the final certificate order in May 2010, the expenditures associated with the Kemper IGCC of approximately $116.2 million of regulatory assets, deferred was reclassified to CWIP during the second quarter 2010. Securities due within one year increased by $255.1 million primarily due to the reclassification of an $80.0 million long-term bank loan maturing in March 2011, a $125.0 million bank loan maturing in September 2011, and the redemption of $50.0 million second series revenue bonds on February 8, 2011. Over recovered regulatory clause liabilities increased $28.5 million primarily due to lower fuel costs and the implementation of higher fuel rates in 2009 as compared to 2010. Long-term debt decreased $31.4 million primarily due to the reclassification of an $80.0 million long-term bank loan maturing in March 2011 partially offset by obligations incurred relating to a $50.0 million issuance of revenue bonds. The change in accumulated deferred income taxes of $58.9 million was primarily due to bonus depreciation, LTSA, and funding of the qualified pension plan. Employee benefit obligations decreased by $47.8 million primarily due to the funding of the qualified pension plan. Paid in capital increased $67.2 million primarily due to the capital contribution from Southern Company.

The Company's ratio of common equity to total capitalization, excluding long-term debt due within one year, increased from 55.6% in 2009 to 59.8% at December 31, 2010.

Sources of Capital

Except as described below with respect to potential DOE loan guarantees, the Company plans to obtain the funds required for construction and other purposes from sources such as operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. In December 2010, the Company received $60 million in capital contributions from Southern Company. See "Capital Requirements and Contractual Obligations" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. The amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

In addition, the Company has applied to the DOE for federal loan guarantees to finance a portion of the eligible construction costs of the Kemper IGCC. The Company is in advanced due diligence with the DOE but has yet to begin discussions with the DOE regarding the terms and conditions of any loan guarantee. There can be no assurance that the DOE will issue federal loan guarantees to the Company. In addition, the Company has been awarded DOE CCPI2 grant funds of $245 million to be used for the construction of the Kemper IGCC and $25 million to be used for the initial operation of the plant. As of December 31, 2010, the Company had received $23.1 million and billed an additional $9.5 million associated with this grant.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts 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. 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.

To meet short-term cash needs and contingencies, the Company has various sources of liquidity. At December 31, 2010, the Company had approximately $160.8 million of cash and cash equivalents, $50.0 million of restricted cash, and $161.0 million of unused credit arrangements with banks. 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 $90.1 million outstanding revenue bonds requiring liquidity support. Subsequent to December 31, 2010, $50.0 million of revenue bonds were redeemed on February 8, 2011, reducing liquidity support to $40.1 million. 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 operating company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support. At December 31, 2010 and 2009, the Company had no commercial paper outstanding.

During 2010, the maximum amount outstanding for commercial paper was $63.0 million and the average amount outstanding was $12.0 million. During 2009, the maximum amount outstanding for commercial paper was $66.7 million and the average amount outstanding was $15.9 million. The weighted average annual interest rate on commercial paper was 0.3% for 2010 and 0.3% for 2009.

Financing Activities

In September 2010, the Company entered into a one-year $125 million aggregate principal amount long-term floating rate bank loan that bears interest based on the one-month London Interbank Offered Rate. The proceeds were used to repay a portion of the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program. In December 2010, the Company incurred obligations in connection with the issuance of $100 million of revenue bonds in two series, each of which is due December 1, 2040. The first series of $50 million was issued with an initial fixed rate of 2.25% through January 14, 2013 and the second series of $50 million was issued with a floating rate. The proceeds from the first series bonds were used to finance the acquisition and construction of buildings and immovable equipment in connection with the Company's construction of the Kemper IGCC facility in Kemper County, Mississippi. Proceeds from the second series were classified as restricted cash at December 31, 2010. The second series bonds were redeemed on February 8, 2011.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm restoration costs, 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.

Off-Balance Sheet Financing Arrangements

In 2001, the Company began an initial 10-year term of a lease agreement for a combined cycle generating facility built at Plant Daniel. In June 2003, the Company entered into a restructured lease agreement for the Facility with Juniper, as discussed in Note 7 to the financial statements under "Operating Leases – Plant Daniel Combined Cycle Generating Units." Juniper has also entered into leases with other parties unrelated to the Company. The assets leased by the Company comprise less than 50% of Juniper's assets. The Company does not consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. Accordingly, the lease is not reflected in the balance sheets.

The initial lease term ends in 2011, and the lease includes a renewal and a purchase option based on the cost of the facility at the inception of the lease, which was approximately $370 million. The Company is required to amortize approximately 4% of the initial acquisition cost over the initial lease term. In April 2010, the Company was required to notify the lessor, Juniper, if it intended to terminate the lease at the end of the initial term expiring in October 2011. The Company chose not to give notice to terminate the lease. The Company has the option to purchase the Plant Daniel combined cycle generating units for approximately $354 million or renew the lease for approximately $31 million annually for 10 years. The Company will have to provide notice of its intent to either renew the lease or purchase the facility by July 2011. The ultimate outcome of this matter cannot be determined at this time.

The lease also provides for a residual value guarantee, approximately 73% of the acquisition cost, by the Company that is due upon termination of the lease in the event that the Company does not renew the lease or purchase the Facility and that the fair market value is less than the unamortized cost of the Facility. See Note 7 to the financial statements under "Operating Leases – Plant Daniel Combined Cycle Generating Units" for additional information.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are for physical electricity sales, fuel purchases, fuel transportation and storage, emissions allowances, and energy price risk management. At December 31, 2010, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $353 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 Services (Moody's) downgraded the issuer and long-term debt ratings of the Company (senior unsecured to A2 from A1). 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 stock ratings of the Company (to Baa1 from A3). Moody's announced that the ratings outlook for the Company is stable.

On September 3, 2010, Fitch Ratings, Inc (Fitch) downgraded the issuer and long-term debt ratings of the Company (senior unsecured to A+ from AA- and issuer default rating to A from A+). Fitch also announced that it had downgraded the short-term ratings of the Company to F1 from F1+. In addition, Fitch announced that it had downgraded the pollution control revenue bond ratings of the Company to A+ from AA- and the preferred stock ratings of the Company (to A- from A). Fitch 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, foreign currency, 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 that include, but are not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

The Company does not currently hedge interest rate risk. The weighted average interest rate on $295 million of variable rate long-term debt at January 1, 2011 was 0.56%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $3.0 million at January 1, 2011.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. At December 31, 2010, exposure from these activities was not material to the Company's financial statements.

In addition, per the guidelines of the Mississippi PSC, the Company has implemented a fuel-hedging program. At December 31, 2010, exposure from these activities was not material to the Company's financial statements.

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	**$(41,734)**	$(51,985)
Contracts realized or settled	**32,853**	53,905
Current period changes[a]	**(34,889)**	(43,654)
Contracts outstanding at the end of the period, assets (liabilities), net	**$(43,770)**	$(41,734)

(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 a decrease of $2.0 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 24.0 million mmBtu with a weighted average contract cost of approximately $1.92 per mmBtu above market prices, and 23.2 million mmBtu at December 31, 2009 with a weighted average contract cost of approximately $1.83 per mmBtu above market prices. The majority of the natural gas hedges are recovered through the Company's ECM 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 ECM clause. Gains and losses on energy-related derivatives that are designated as cash flow hedges are used to hedge anticipated purchases and sales and are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented. The pre-tax gains/(losses) reclassified from other comprehensive income to revenue and fuel expense were not material for any period presented and are not expected to be material for 2011. Additionally, there was no material ineffectiveness recorded in earnings for any period 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	(43,770)	(26,622)	(17,148)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(43,770)	$(26,622)	$(17,148)	$ -

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 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 $818 million, $1.0 billion, and $878 million for 2011, 2012, and 2013, respectively. Included in these estimated amounts are expenditures related to the Kemper IGCC of $665 million, $813 million, and $616 million in 2011, 2012, and 2013, respectively. Also included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $45 million, $94 million, and $127 million for 2011, 2012, and 2013, respectively. In addition, the Company currently estimates that potential incremental investments to comply with anticipated new environmental regulations are $0 for 2011, up to $18 million for 2012, and up to $55 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 retirement and replacement decisions, to meet new regulatory requirements; changes in FERC rules and regulations; Mississippi 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. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

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.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred 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	$ 255,000	$ 50,000	$ -	$412,695	$ -	$ 717,695
Interest	23,649	44,134	38,101	213,401	-	319,285
Preferred stock dividends[b]	1,733	3,465	3,465	-	-	8,663
Energy-related derivative obligations[c]	27,459	18,386	-	-	-	45,845
Unrecognized tax benefits and interest[d]	-	-	-	-	4,701	4,701
Operating leases [e]	38,513	18,562	9,151	1,045		67,271
Capital leases[f]	1,437	633	-	-	-	2,070
Purchase commitments[g] –						
Capital[h]	818,004	1,899,388	-	-	-	2,717,392
Coal	324,360	145,405	9,400	36,480	-	515,645
Natural gas[i]	180,653	246,995	177,012	162,723	-	767,383
Long-term service agreements[j]	13,272	27,413	28,658	55,231	-	124,574
Pension and other postretirement benefits plans[k]	275	549	-	-	-	824
Foreign currency derivatives[l]	66	29	-	-	-	95
Total	$1,684,421	$2,454,959	$265,787	$881,575	$ 4,701	$5,291,443

(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. Long-term debt excludes capital lease amounts (shown separately).

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

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

(d) The timing related to the realization of $4.7 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 decrease from 2011 to 2012-2013 is primarily a result of the Plant Daniel operating lease contract that is scheduled to end during 2011, at which time the Company can exercise a purchase option or renew the lease. See Note 7 to the financial statements for additional information.

(f) The capital lease of $6.4 million is being amortized over a five-year period ending in 2012.

(g) 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 $268 million, $247 million, and $260 million, respectively.

(h) 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 $0 for 2011, up to $18 million for 2012, and up to $55 million for 2013. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. Estimates include the sale of 17.5% of the Kemper IGCC to SMEPA. At December 31, 2010, significant purchase commitments were outstanding in connection with the construction program.

(i) 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.

(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.

(l) For additional information, see Note 10 to the financial statements.

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, customer growth, storm damage cost recovery and repairs, economic recovery, fuel cost recovery, and other rate actions, environmental regulations and expenditures, future earnings, access to sources of capital, 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, hazardous air pollutants, including mercury, carbon, soot, particulate matter, and coal combustion byproducts 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 EPA civil actions;
- 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;
- regulatory approvals and actions related to the Kemper IGCC, including Mississippi PSC approvals and potential DOE loan guarantees;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- 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

Mississippi Power Company 2010 Annual Report

	2010	2009	2008
		(in thousands)	
Operating Revenues:			
Retail revenues	**$797,912**	$790,950	$785,434
Wholesale revenues, non-affiliates	**287,917**	299,268	353,793
Wholesale revenues, affiliates	**41,614**	44,546	100,928
Other revenues	**15,625**	14,657	16,387
Total operating revenues	**1,143,068**	1,149,421	1,256,542
Operating Expenses:			
Fuel	**501,830**	519,687	586,503
Purchased power, non-affiliates	**8,426**	8,831	27,036
Purchased power, affiliates	**75,230**	83,104	99,526
Other operations and maintenance	**268,063**	246,758	260,011
Depreciation and amortization	**76,891**	70,916	71,039
Taxes other than income taxes	**69,810**	64,068	65,099
Total operating expenses	**1,000,250**	993,364	1,109,214
Operating Income	**142,818**	156,057	147,328
Other Income and (Expense):			
Allowance for equity funds used during construction	**3,795**	387	560
Interest income	**215**	804	1,998
Interest expense, net of amounts capitalized	**(22,341)**	(22,940)	(17,979)
Other income (expense), net	**3,738**	2,606	4,135
Total other income and (expense)	**(14,593)**	(19,143)	(11,286)
Earnings Before Income Taxes	**128,225**	136,914	136,042
Income taxes	**46,275**	50,214	48,349
Net Income	**81,950**	86,700	87,693
Dividends on Preferred Stock	**1,733**	1,733	1,733
Net Income After Dividends on Preferred Stock	**$ 80,217**	$ 84,967	$ 85,960

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
Mississippi Power Company 2010 Annual Report

	2010	2009	2008
		(in thousands)	
Operating Activities:			
Net income	**$ 81,950**	$ 86,700	$ 87,693
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**82,294**	78,914	75,765
Deferred income taxes	**37,557**	(39,849)	24,840
Investment tax credits received	**22,173**	-	-
Allowance for equity funds used during construction	**(3,795)**	(387)	(560)
Pension, postretirement, and other employee benefits	**(34,911)**	7,077	8,182
Stock based compensation expense	**1,186**	886	724
Tax benefit of stock options	**399**	34	489
Generation construction screening costs	**(50,554)**	(30,638)	(26,662)
Other, net	**(3,803)**	(3,263)	(20,207)
Changes in certain current assets and liabilities --			
-Receivables	**(8,185)**	9,677	(9,982)
-Under recovered regulatory clause revenues	**-**	54,994	(14,450)
-Fossil fuel stock	**14,997**	(41,699)	(38,072)
-Materials and supplies	**(879)**	(649)	297
-Prepaid income taxes	**(17,075)**	1,061	3,243
-Other current assets	**(4,633)**	2,065	(2,022)
-Other accounts payable	**(12,630)**	(7,590)	3,251
-Accrued taxes	**(4,268)**	8,800	2,428
-Accrued compensation	**2,291**	(6,819)	(1,362)
-Over recovered regulatory clause revenues	**28,450**	48,596	-
-Other current liabilities	**2,137**	2,732	836
Net cash provided from operating activities	**132,701**	170,642	94,431
Investing Activities:			
Property additions	**(247,005)**	(101,995)	(153,401)
Investment in restricted cash	**(50,000)**	-	-
Cost of removal net of salvage	**(9,240)**	(9,352)	(6,411)
Construction payables	**33,767**	(5,091)	(4,084)
Capital grant proceeds	**23,657**	-	7,314
Other investing activities	**(5,587)**	(2,971)	819
Net cash used for investing activities	**(254,408)**	(119,409)	(155,763)
Financing Activities:			
Increase (decrease) in notes payable, net	**-**	(26,293)	16,350
Proceeds --			
Capital contributions from parent company	**65,215**	4,567	3,541
Gross excess tax benefit of stock options	**624**	117	934
Pollution control revenue bonds	**-**	-	7,900
Senior notes issuances	**-**	125,000	50,000
Other long-term debt issuances	**225,000**	-	80,000
Redemptions --			
Pollution control revenue bonds	**-**	-	(7,900)
Capital leases	**(1,330)**	-	-
Senior notes	**-**	(40,000)	-
Payment of preferred stock dividends	**(1,733)**	(1,733)	(1,733)
Payment of common stock dividends	**(68,600)**	(68,500)	(68,400)
Other financing activities	**(1,715)**	(1,779)	(1,774)
Net cash provided from (used for) financing activities	**217,461**	(8,621)	78,918
Net Change in Cash and Cash Equivalents	**95,754**	42,612	17,586
Cash and Cash Equivalents at Beginning of Year	**65,025**	22,413	4,827
Cash and Cash Equivalents at End of Year	**$ 160,779**	$ 65,025	$ 22,413
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $2,903, $117 and $229 capitalized, respectively)	**$19,518**	$19,832	$15,753
Income taxes (net of refunds)	**7,546**	77,206	23,829
Noncash transactions - accrued property additions at year-end	**37,736**	3,689	8,776

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

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

Assets	**2010**	2009
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 160,779**	$ 65,025
Restricted cash	**50,000**	-
Receivables --		
Customer accounts receivable	**37,532**	36,766
Unbilled revenues	**31,010**	27,168
Other accounts and notes receivable	**11,220**	11,337
Affiliated companies	**17,837**	13,215
Accumulated provision for uncollectible accounts	**(638)**	(940)
Fossil fuel stock, at average cost	**112,240**	127,237
Materials and supplies, at average cost	**28,671**	27,793
Other regulatory assets, current	**63,896**	53,273
Prepaid income taxes	**59,596**	32,237
Other current assets	**19,057**	12,625
Total current assets	**591,200**	405,736
Property, Plant, and Equipment:		
In service	**2,392,477**	2,316,494
Less accumulated provision for depreciation	**971,559**	950,373
Plant in service, net of depreciation	**1,420,918**	1,366,121
Construction work in progress	**274,585**	48,219
Total property, plant, and equipment	**1,695,503**	1,414,340
Other Property and Investments	**5,900**	7,018
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**18,065**	8,536
Other regulatory assets, deferred	**132,420**	209,100
Other deferred charges and assets	**33,233**	27,951
Total deferred charges and other assets	**183,718**	245,587
Total Assets	**$2,476,321**	$2,072,681

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

BALANCE SHEETS

At December 31, 2010 and 2009

Mississippi Power Company 2010 Annual Report

Liabilities and Stockholder's Equity	**2010**	2009
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 256,437**	$ 1,330
Accounts payable --		
Affiliated	**51,887**	49,209
Other	**59,295**	38,662
Customer deposits	**12,543**	11,143
Accrued taxes --		
Accrued income taxes	**4,356**	10,590
Other accrued taxes	**51,709**	49,547
Accrued interest	**5,933**	5,739
Accrued compensation	**16,076**	13,785
Other regulatory liabilities, current	**6,177**	7,610
Over recovered regulatory clause liabilities	**77,046**	48,596
Liabilities from risk management activities	**27,525**	19,454
Other current liabilities	**20,115**	21,142
Total current liabilities	**589,099**	276,807
Long-Term Debt (See accompanying statements)	**462,032**	493,480
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**281,967**	223,066
Deferred credits related to income taxes	**11,792**	13,937
Accumulated deferred investment tax credits	**33,678**	12,825
Employee benefit obligations	**113,964**	161,778
Other cost of removal obligations	**111,614**	97,820
Other regulatory liabilities, deferred	**58,814**	54,576
Other deferred credits and liabilities	**43,213**	47,090
Total deferred credits and other liabilities	**655,042**	611,092
Total Liabilities	**1,706,173**	1,381,379
Redeemable Preferred Stock (See accompanying statements)	**32,780**	32,780
Common Stockholder's Equity (See accompanying statements)	**737,368**	658,522
Total Liabilities and Stockholder's Equity	**$2,476,321**	$2,072,681
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
Mississippi Power Company 2010 Annual Report

	2010	2009	**2010**	2009
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
6.00% due 2013	**50,000**	50,000		
2.25% to 5.625% due 2017-2040	**330,000**	280,000		
Adjustable rates (0.56% to 0.71% at 1/1/11) due 2011	**205,000**	80,000		
Adjustable rates (0.44% at 1/1/11) due 2040	**50,000**	-		
Total long-term notes payable	**635,000**	410,000		
Other long-term debt --				
Pollution control revenue bonds:				
5.15% due 2028	**42,625**	42,625		
Variable rates (0.34% to 0.51% at 1/1/11) due 2020-2028	**40,070**	40,070		
Total other long-term debt	**82,695**	82,695		
Capitalized lease obligations	**2,070**	3,399		
Unamortized debt discount	**(1,296)**	(1,284)		
Total long-term debt (annual interest requirement -- $23.6 million)	**718,469**	494,810		
Less amount due within one year	**256,437**	1,330		
Long-term debt excluding amount due within one year	**462,032**	493,480	**37.5%**	41.6%
Cumulative Redeemable Preferred Stock:				
$100 par value				
Authorized: 1,244,139 shares				
Outstanding: 334,210 shares				
4.40% to 5.25% (annual dividend requirement -- $1.7 million)	**32,780**	32,780	**2.7**	2.8
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized: 1,130,000 shares				
Outstanding: 1,121,000 shares	**37,691**	37,691		
Paid-in capital	**392,790**	325,562		
Retained earnings	**306,885**	295,269		
Accumulated other comprehensive income (loss)	**2**	-		
Total common stockholder's equity	**737,368**	658,522	**59.8**	55.6
Total Capitalization	**$1,232,180**	$1,184,782	**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
Mississippi Power Company 2010 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in thousands)		
Balance at December 31, 2007	1,121	$37,691	$314,324	$261,242	$573	$613,830
Net income after dividends on preferred stock	-	-	-	85,960	-	85,960
Capital contributions from parent company	-	-	5,634	-	-	5,634
Other comprehensive income (loss)	-	-	-	-	(573)	(573)
Cash dividends on common stock	-	-	-	(68,400)	-	(68,400)
Balance at December 31, 2008	1,121	37,691	319,958	278,802	-	636,451
Net income after dividends on preferred stock	-	-	-	84,967	-	84,967
Capital contributions from parent company	-	-	5,604	-	-	5,604
Other comprehensive income (loss)	-	-	-	-	-	-
Cash dividends on common stock	-	-	-	(68,500)	-	(68,500)
Balance at December 31, 2009	**1,121**	**37,691**	**325,562**	**295,269**	**-**	**658,522**
Net income after dividends on preferred stock	**-**	**-**	**-**	**80,217**	**-**	**80,217**
Capital contributions from parent company	**-**	**-**	**67,228**	**-**	**-**	**67,228**
Other comprehensive income (loss)	**-**	**-**	**-**	**-**	**2**	**2**
Cash dividends on common stock	**-**	**-**	**-**	**(68,600)**	**-**	**(68,600)**
Other	**-**	**-**	**-**	**(1)**	**-**	**(1)**
Balance at December 31, 2010	**1,121**	**$37,691**	**$392,790**	**$306,885**	**$ 2**	**$737,368**

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

Mississippi Power Company 2010 Annual Report

	2010	2009	2008
		(in thousands)	
Net income after dividends on preferred stock	**$80,217**	$84,967	$85,960
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $1, $-, and $(355), respectively	**2**	-	(573)
Comprehensive Income	**$80,219**	$84,967	$85,387

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Mississippi 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 – Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and the Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing service to retail customers in southeast Mississippi 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 and for variable interest entities where the Company has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Mississippi Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $125.1 million, $84.0 million, and $87.1 million during 2010, 2009, and 2008, respectively. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission 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 provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. The Company provided no significant service to an affiliate in 2010, 2009, and 2008. The Company received storm restoration assistance from other Southern Company subsidiaries totaling $3.2 million in 2008. There was no storm assistance received in 2010 or 2009.

In June 2010, the Company purchased a turbine rotor assembly part from Gulf Power for approximately $6 million. In September 2010, Southern Power purchased a turbine rotor assembly part owned by the Company for approximately $7 million. These affiliate transactions were in accordance with FERC and state PSC rules and guidelines.

The Company has an agreement with Alabama Power under which the Company owns a portion of Greene County Steam Plant. Alabama Power operates Greene County Steam Plant, and the Company reimburses Alabama Power for its proportionate share of all associated expenditures and costs. The Company reimbursed Alabama Power for the Company's proportionate share of related expenses which totaled $11.2 million, $10.2 million, and $11.1 million in 2010, 2009, and 2008, respectively. The Company also has an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs. Gulf Power reimbursed the Company for Gulf Power's proportionate share of related expenses which totaled $25.0 million, $20.9 million, and $22.8 million in 2010, 2009, and 2008, respectively. See Note 4 for additional information.

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

Regulatory Assets and Liabilities

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

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

	2010	2009	Note
	(in thousands)		
Hurricane Katrina	**$ (143)**	$ (143)	(a)
Retiree benefit plans	**86,748**	99,690	(b,k)
Property damage	**(61,171)**	(57,814)	(m)
Deferred income tax charges	**13,654**	9,027	(d)
Property tax	**18,649**	17,170	(e)
Transmission & distribution deferral	**2,367**	4,734	(f)
Vacation pay	**9,143**	8,756	(g,k)
Loss on reacquired debt	**7,775**	8,409	(h)
Loss on redeemed preferred stock	**57**	229	(i)
Loss on rail cars	**8**	108	(h)
Other regulatory assets	**-**	1,087	(c)
Fuel-hedging (realized and unrealized) losses	**48,729**	44,116	(j,k)
Asset retirement obligations	**9,302**	8,955	(d)
Deferred income tax credits	**(13,189)**	(14,853)	(d)
Other cost of removal obligations	**(111,614)**	(97,820)	(d)
Fuel-hedging (realized and unrealized) gains	**(2,067)**	(551)	(j,k)
Generation screening costs	**12,295**	68,496	(l)
Other liabilities	**(81)**	(2,628)	(c)
Deferred income tax charges − Medicare subsidy	**5,521**	-	(n)
Total assets (liabilities), net	**$ 25,983**	$ 96,968	

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

(a) For additional information, see Note 3 under "Retail Regulatory Matters – Storm Damage Cost Recovery."
(b) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.
(c) Recorded and recovered as approved by the Mississippi PSC over periods not exceeding two years.
(d) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.
(e) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year.
(f) Amortized over a four-year period ending December 2011.
(g) Recorded as earned by employees and recovered as paid, generally within one year.
(h) Recovered over the remaining life of the original issue/lease or, if refinanced, over the life of the new issue/lease, which may range up to 50 years.
(i) Amortized over a seven-year period ending in April 2011.
(j) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, costs are recovered through the Energy Cost Management clause (ECM).
(k) Not earning a return as offset in rate base by a corresponding asset or liability.
(l) For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle."
(m) For additional information, see Note 1 under "Provision for Property Damage" and Note 3 under "Retail Regulatory Matters – System Restoration Rider."
(n) Recovered and amortized over a 10-year period beginning in 2011, as approved by the Mississippi PSC for the retail portion and a five-year period for the wholesale portion, as approved by FERC. See Note 5 for additional information.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

Government Grants

The Company received a grant in October 2006 from the Mississippi Development Authority (MDA) for $276.4 million, primarily for storm damage cost recovery. In 2007, the Company received $109.3 million of storm restoration bond proceeds under the state bond program of which $25.2 million was for retail storm restoration costs, $60.0 million was to increase the Company's retail property damage reserve, and $24.1 million was to cover the retail portion of construction of a new storm operations center. In 2008, the Company received grant payments in the amount of $7.3 million and anticipates the receipt of approximately $3.2 million in 2011. The grant proceeds do not represent a future obligation of the Company. The portion of any grants received related to retail storm recovery was applied to the retail regulatory asset that was established as restoration costs were incurred. The portion related to wholesale storm recovery was recorded either as a reduction to operations and maintenance expense or as a reduction to total property, plant, and equipment depending on the restoration work performed and the appropriate allocations of cost of service.

In August 2010, the Department of Energy (DOE), through a cooperative agreement with SCS, agreed to fund $270 million of the Kemper integrated coal gasification combined cycle (IGCC) through the Clean Coal Power Initiative Round 2 (CCPI2) funds. As of December 31, 2010, the Company had collected $23.1 million and billed an additional $9.5 million, for a total of $32.6 million, which is reflected in the Company's financial statements as a reduction to the Kemper IGCC capital costs.

Revenues

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery factor annually.

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. Fuel costs also include gains and/or losses from fuel hedging programs as approved by the Mississippi PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less 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 for projects over $1 million where recovery of construction work in progress is not allowed in rates.

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

	2010	2009
	(in thousands)	
Generation	**$ 990,151**	$ 963,145
Transmission	**464,716**	449,452
Distribution	**765,578**	748,066
General	**172,032**	155,831
Total plant in service	**$2,392,477**	$2,316,494

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 except for the cost of maintenance of coal cars and a portion of the railway track maintenance costs, which are charged to fuel stock and recovered through the Company's fuel clause.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.4% in 2010, 3.3% in 2009, and 3.3% in 2008. Depreciation studies are conducted periodically to update the composite rates. 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. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation includes an amount for the expected cost of removal of facilities. In September 2009, the Company filed a depreciation study as of December 31, 2008, with the Mississippi PSC and the FERC. The FERC accepted this study in October 2009. On April 20, 2010, the Mississippi PSC issued an order approving the depreciation rates effective January 1, 2010. This change did not have a material impact on the financial statements.

In April 2007, the Mississippi PSC issued an order allowing the Company to defer certain reliability related maintenance costs beginning January 1, 2007 and recover them evenly over a four-year period beginning January 1, 2008. These costs related to maintenance that was needed as follow-up to emergency repairs that were made subsequent to Hurricane Katrina. At December 31, 2007, the Company had incurred and deferred the retail portion of $9.5 million of such costs. At December 31, 2010, the Company had a balance of the deferred retail portion of $2.4 million in other regulatory assets.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Mississippi 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 Company has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, co-generation 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 Mississippi 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	**$17,431**	$17,977
Liabilities incurred	**(1)**	378
Liabilities settled	**155**	(1,892)
Accretion	**1,016**	1,049
Cash flow revisions	**-**	(81)
Balance at end of year	**$18,601**	$17,431

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, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 7.33%, 7.92%, and 6.9% for the years ended December 31, 2010, 2009, and 2008, respectively. The AFUDC rate is applied to construction work in progress based on jurisdictional regulatory recovery mechanisms. AFUDC, net of income taxes as a percentage of net income after dividends on preferred stock was 6.97%, 0.5%, and 0.82% 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 asset 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.

Provision for Property Damage

The Company carries insurance for the cost of certain types of damage to generation plants and general property. However, the Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, the Company accrues for the cost of such damage through an annual expense accrual credited to regulatory liability accounts for the retail and wholesale jurisdictions. The cost of repairing actual damage resulting from such events that individually exceed $50,000 is charged to the reserve. The Company made no discretionary retail accruals in 2008 as a result of the Hurricane Katrina-related financing order issued by the Mississippi PSC which ordered the Company to cease all accruals to the retail property damage reserve until a new reserve cap was established. However, in the same financing order, the Mississippi PSC approved the replenishment of the retail property damage reserve with $60 million that was funded with a portion of the proceeds of bonds issued by the Mississippi Development Bank on behalf of the State of Mississippi and reported as liabilities by the State of Mississippi. In January 2009, the Mississippi PSC approved the System Restoration Rider (SRR) stipulation between the Company and the Mississippi Public Utilities Staff. In accordance with the stipulation, every three years the Mississippi PSC, Mississippi Public Utilities Staff, and the Company will agree on SRR revenue level(s) for the ensuing period, based on historical data, expected exposure, type and amount of insurance coverage, excluding insurance cost, and any other relevant information. The accrual amount and the reserve balance are determined based on the SRR revenue level(s). If a significant change in circumstances occurs, then the SRR revenue level can be adjusted more frequently if the Company and the Mississippi Public Utilities Staff or the Mississippi PSC deem the change appropriate. Each year the Company will set rates to collect the approved SRR revenues. The property damage reserve accrual will be the difference between the approved SRR revenues and the SRR revenue requirement, excluding any accrual to the reserve. In 2010 and 2009, the Company made retail accruals of $3.1 million and $3.7 million, respectively, per the annual SRR rate filings. In addition, SRR allows the Company to set up a regulatory asset, pending review, if the allowable actual retail property damage costs exceed the amount in the retail property damage reserve. See Note 3 under "Retail Regulatory Matters – Storm Damage Cost Recovery" and "Retail Regulatory Matters – System Restoration Rider" for additional information. The Company accrued $0.3 million annually in 2010 and 2009, and $0.2 million in 2008 for the wholesale jurisdiction.

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.

Restricted Cash

In December 2010, the Company incurred obligations relating to the issuance of $50 million of revenue bonds. The proceeds of this issuance are presented as restricted cash on the balance sheet at December 31, 2010. These bonds were redeemed on February 8, 2011. See Note 6 under "Revenue Bonds" for additional information.

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 Mississippi 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 the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. 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 the fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Mississippi PSC approved fuel hedging program as discussed below. 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 Mississippi PSC has approved the Company's request to implement an ECM which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

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.

Variable Interest Entities

Effective January 1, 2010, the Company adopted new accounting guidance which modified the consolidation model and expanded disclosures related to variable interest entities (VIE). The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. The adoption of this new accounting guidance did not result in the Company consolidating any VIEs that were not already consolidated under previous guidance, nor deconsolidating any VIEs.

The Company is required to provide financing for all costs associated with the mine development and operation under a contract with Liberty Fuels Company, LLC (Liberty Fuels) in conjunction with the construction of the Kemper IGCC. Liberty Fuels qualifies as a VIE for which the Company is the primary beneficiary. As of December 31, 2010, Liberty Fuels did not have a material impact on the financial position and results of operations of the Company.

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 $43 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 postretirement trusts to the extent required by the FERC. For the year ending December 31, 2011, other postretirement trust contributions are expected to total approximately $0.3 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 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	**5.51%**	5.92%	6.75%
Other postretirement benefit plans	**5.39**	5.83	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	**7.65**	7.62	7.85

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	1Percent Decrease
	(in thousands)	
Benefit obligation	$ 5,786	$ 4,930
Service and interest costs	310	264

Pension Plans

The total accumulated benefit obligation for the pension plans was $307 million in 2010 and $289 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	**$309,179**	$266,879
Service cost	**8,300**	6,792
Interest cost	**17,916**	17,577
Benefits paid	**(12,206)**	(11,965)
Plan amendments	**48**	-
Actuarial loss (gain)	**7,078**	29,896
Balance at end of year	**330,315**	309,179
Change in plan assets		
Fair value of plan assets at beginning of year	**218,015**	198,510
Actual return (loss) on plan assets	**33,780**	30,088
Employer contributions	**44,109**	1,382
Benefits paid	**(12,206)**	(11,965)
Fair value of plan assets at end of year	**283,698**	218,015
Accrued liability	**$(46,617)**	$(91,164)

At December 31, 2010, the projected benefit obligations for the qualified and non-qualified pension plans were $305 million and $25 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 plan consist of the following:

	2010	2009
	(in thousands)	
Other regulatory assets, deferred	**$78,130**	$85,357
Other current liabilities	**(1,516)**	(1,484)
Employee benefit obligations	**(45,101)**	(89,680)

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	**$ 7,879**	$ 9,222	**$ 1,309**
Net (gain) loss	**70,251**	76,135	**1,114**
Other regulatory assets, deferred	**$ 78,130**	$ 85,357	

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	$ 66,602
Net loss	20,872
Change in prior service costs	-
Reclassification adjustments:	
Amortization of prior service costs	(1,578)
Amortization of net gain	(539)
Total reclassification adjustments	(2,117)
Total change	18,755
Balance at December 31, 2009	$ 85,357
Net (gain)	(5,250)
Change in prior service costs	48
Reclassification adjustments:	
Amortization of prior service costs	(1,391)
Amortization of net gain	(634)
Total reclassification adjustments	(2,025)
Total change	(7,227)
Balance at December 31, 2010	$ 78,130

Components of net periodic pension cost were as follows:

	2010	2009	2008
		(in thousands)	
Service cost	**$ 8,300**	$ 6,792	$ 6,846
Interest cost	**17,916**	17,577	15,802
Expected return on plan assets	**(21,451)**	(21,065)	(20,611)
Recognized net (gain) loss	**634**	539	481
Net amortization	**1,391**	1,578	1,668
Net periodic pension cost	**$ 6,790**	$ 5,421	$ 4,186

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	$13,753
2012	14,847
2013	15,763
2014	16,753
2015	17,691
2016 to 2020	105,208

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	**$ 83,774**	$ 84,733
Service cost	**1,305**	1,328
Interest cost	**4,763**	5,535
Benefits paid	**(4,245)**	(4,041)
Actuarial gain	**(2,511)**	(1,550)
Plan amendments	**(1,824)**	(2,592)
Retiree drug subsidy	**426**	361
Balance at end of year	**81,688**	83,774
Change in plan assets		
Fair value of plan assets at beginning of year	**20,292**	18,623
Actual return (loss) on plan assets	**2,297**	2,902
Employer contributions	**2,185**	2,447
Benefits paid	**(3,819)**	(3,680)
Fair value of plan assets at end of year	**20,955**	20,292
Accrued liability	**$(60,733)**	$(63,482)

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)	
Other regulatory assets, deferred	**$ 8,618**	$ 14,332
Employee benefit obligations	**(60,733)**	(63,482)

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	**$ (2,873)**	$ (1,107)	**$ (188)**
Net (gain) loss	**11,092**	14,811	**234**
Transition obligation	**399**	628	**228**
Other regulatory assets, deferred	**$ 8,618**	$ 14,332	

The changes in the balance of regulatory assets 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
	(in thousands)
Balance at December 31, 2008	$ 20,491
Net gain	(2,648)
Change in prior service costs/transition obligation	(2,592)
Reclassification adjustments:	
Amortization of transition obligation	(307)
Amortization of prior service costs	(51)
Amortization of net gain	(561)
Total reclassification adjustments	(919)
Total change	(6,159)
Balance at December 31, 2009	$ 14,332
Net gain	**(3,316)**
Change in prior service costs/transition obligation	**(1,824)**
Reclassification adjustments:	
Amortization of transition obligation	**(228)**
Amortization of prior service costs	**57**
Amortization of net gain	**(403)**
Total reclassification adjustments	**(574)**
Total change	**(5,714)**
Balance at December 31, 2010	**$ 8,618**

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

	2010	2009	2008
		(in thousands)	
Service cost	**$ 1,305**	$ 1,328	$ 1,396
Interest cost	**4,763**	5,535	5,199
Expected return on plan assets	**(1,826)**	(1,783)	(1,805)
Net amortization	**574**	919	1,066
Net postretirement cost	**$ 4,816**	$ 5,999	$ 5,856

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 $1.6 million, $1.7 million, and $1.8 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	$ 4,745	$ (489)	$ 4,256
2012	5,098	(556)	4,542
2013	5,544	(614)	4,930
2014	5,861	(686)	5,175
2015	6,214	(751)	5,463
2016 to 2020	33,655	(3,735)	29,920

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	23%	**23%**	26%
International equity	22	**22**	22
Fixed income	32	**38**	34
Special situations	3	**-**	-
Real estate investments	12	**10**	10
Private equity	8	**7**	8
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*	$ 52,553	$21,208	$ 28	$ 73,789
International equity*	53,006	18,377	-	71,383
Fixed income:				
U.S. Treasury, government, and agency bonds	-	12,629	-	12,629
Mortgage- and asset-backed securities	-	10,250	-	10,250
Corporate bonds	-	24,663	85	24,748
Pooled funds	-	8,353	-	8,353
Cash equivalents and other	85	19,849	-	19,934
Special situations	-	-	-	-
Real estate investments	7,645	-	27,976	35,621
Private equity	-	-	26,475	26,475
Total	$113,289	$115,329	$54,564	$283,182
Liabilities:				
Derivatives	(28)	-	-	(28)
Total	$113,261	$115,329	$54,564	$283,154

*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*	$ 43,279	$17,897	$ -	$ 61,176
International equity*	55,948	5,575	-	61,523
Fixed income:				
U.S. Treasury, government, and agency bonds	-	16,118	-	16,118
Mortgage- and asset-backed securities	-	4,382	-	4,382
Corporate bonds	-	10,803	-	10,803
Pooled funds	-	390	-	390
Cash equivalents and other	108	13,211	-	13,319
Special situations	-	-	-	-
Real estate investments	6,747	-	21,195	27,942
Private equity	-	-	21,498	21,498
Total	$106,082	$68,376	$42,693	$217,151
Liabilities:				
Derivatives	(172)	(43)	-	(215)
Total	$105,910	$68,333	$42,693	$216,936

*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	**$21,195**	**$21,498**	$32,700	$19,092
Actual return on investments:				
Related to investments held at year end	**3,959**	**4,313**	(9,492)	1,322
Related to investments sold during the year	**747**	**747**	(2,516)	387
Total return on investments	**4,706**	**5,060**	(12,008)	1,709
Purchases, sales, and settlements	**2,075**	**(83)**	503	697
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$27,976**	**$26,475**	$21,195	$21,498

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*	$3,049	$ 1,230	$ 1	$ 4,280
International equity*	3,076	1,068	-	4,144
Fixed income:				
U.S. Treasury, government, and agency bonds	-	4,632	-	4,632
Mortgage- and asset-backed securities	-	596	-	596
Corporate bonds	-	1,431	-	1,431
Pooled funds	-	485	-	485
Cash equivalents and other	4	1,408	-	1,412
Special situations	-	-	-	-
Real estate investments	442	-	1,625	2,067
Private equity	-	-	1,538	1,538
Total	$6,571	$10,850	$3,164	$20,585

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

	Fair Value Measurements Using			
As of December 31, 2009:	**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*	$ 3,011	$ 1,245	$ -	$ 4,256
International equity*	3,893	387	-	4,280
Fixed income:				
U.S. Treasury, government, and agency bonds	-	5,155	-	5,155
Mortgage- and asset-backed securities	-	304	-	304
Corporate bonds	-	751	-	751
Pooled funds	-	27	-	27
Cash equivalents and other	8	1,295	-	1,303
Special situations	-	-	-	-
Real estate investments	468	-	1,475	1,943
Private equity	-	-	1,497	1,497
Total	$ 7,380	$ 9,164	$ 2,972	$19,516
Liabilities:				
Derivatives	(12)	(3)	-	(15)
Total	$ 7,368	$ 9,161	$ 2,972	$19,501

*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	**$1,475**	**$1,497**	$2,287	$1,335
Actual return on investments:				
Related to investments held at year end	**29**	**47**	(676)	87
Related to investments sold during the year	**-**	**-**	(171)	28
Total return on investments	**29**	**47**	(847)	115
Purchases, sales, and settlements	**121**	**(6)**	35	47
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$1,625**	**$1,538**	$ 1,475	$1,497

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 $3.8 million, $3.9 million, and $3.7 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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 to the Company with respect to the Company's Plant Watson. 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. In early 2000, the EPA filed a motion to amend its complaint to add the Company as a defendant based on the allegations in the notices of violation. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not re-filed. The original action, now solely against Georgia Power, has been administratively closed since the spring of 2001, and the case has not been reopened. The separate action against Alabama Power is ongoing.

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, including the claim relating to the facility co-owned by the Company. 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 has authority from the Mississippi PSC to recover approved environmental compliance costs through regulatory mechanisms.

In 2003, the Texas Commission on Environmental Quality (TCEQ) designated the Company as a potentially responsible party at a site in Texas. The site was owned by an electric transformer company that handled the Company's transformers as well as those of many other entities. The site owner is bankrupt and the State of Texas has entered into an agreement with the Company and several other utilities to investigate and remediate the site. Amounts expensed during 2008, 2009, and 2010 related to this work were not material. Hundreds of entities have received notices from the TCEQ requesting their participation in the anticipated site remediation. The final impact of this matter on the Company will depend upon further environmental assessment and the ultimate number of potentially responsible parties. The remediation expenses incurred by the Company are expected to be recovered through the Environmental Compliance Overview (ECO) Plan.

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 financial statements.

FERC Matters

In August 2008, the Company filed a request with the FERC for a revised wholesale electric tariff and revised rates. Prior to making this filing, the Company reached a settlement with all of its customers who take service under the tariff. This settlement agreement was filed with the FERC as part of the request. The settlement agreement provided for an increase in annual base wholesale revenues in the amount of $5.8 million, effective January 1, 2009. In addition, the settlement agreement allows the Company to increase its annual accrual for the wholesale portion of property damage to $303,000 per year, to defer any property damage costs prudently incurred in excess of the wholesale property damage reserve balance, and to defer the wholesale portion of the generation screening and evaluation costs associated with the Kemper IGCC. The settlement agreement also provided that the Company will not seek a change in wholesale full-requirements rates before November 1, 2010, except for changes associated with the fuel adjustment clause and the ECM, changes associated with property damages that exceed the amount in the wholesale property damage reserve, and changes associated with costs and expenses associated with environmental requirements affecting fossil fuel generating facilities. In October 2008, the Company received notice that the FERC had accepted the filing effective November 1, 2008, and the revised monthly charges were applied beginning January 1, 2009. As result of the order, the Company reclassified $9.3 million of previously expensed generation screening and evaluation costs to a regulatory asset. See "Integrated Coal Gasification Combined Cycle" herein for additional information.

In October 2010, the Company filed with the FERC a request for revised wholesale electric tariff and rates. Prior to making this filing, the Company reached a settlement with all of its customers who take service under the tariff. This settlement agreement was filed with the FERC as part of the request. The settlement agreement provided for an increase in annual base wholesale revenues in the amount of $4.1 million, effective January 1, 2011. In addition, the settlement agreement allows the Company to implement an emissions allowance cost clause, effective January 1, 2011. The emissions allowance cost clause contains an over and under recovery provision similar to the fuel recovery clause and is projected to collect $6.9 million in 2011. The settlement agreement also provides for collection of $2.8 million of 2010 emissions allowance expense for the period of September 1, 2010 through December 31, 2010 and allows the Company to defer the wholesale portion of the income tax expense associated with the change in taxability of the federal subsidy under the Patient Protection and Affordable Care Act (PPACA) and the Health Care and Education Reconciliation Act of 2010 (together with PPACA, the Acts). On December 7, 2010, the Company received notice that the FERC had accepted the filing effective December 21, 2010. As a result of the FERC acceptance, the $2.8 million of emission allowance revenue is included in the statements of income for 2010. Beginning January 1, 2011, the Company implemented the wholesale emissions allowance cost clause and revised monthly charges for the increase in annual base wholesale revenues.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, have been named as defendants in numerous lawsuits brought by landowners since 2001. The plaintiffs' lawsuits claim that defendants may not use, or sublease to third parties, some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties and that such actions exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment and seek compensatory and punitive damages and injunctive relief. Management of the Company believes that it has complied with applicable laws and that the plaintiffs' claims are without merit.

To date, the Company has entered into agreements with plaintiffs in approximately 95% of the actions pending against the Company to clarify the Company's easement rights in the State of Mississippi. These agreements have been approved by the Circuit Courts of Harrison County and Jasper County, Mississippi (First Judicial Circuit), and the related cases have been dismissed. These agreements have not resulted in any material effects on the Company's financial statements.

In addition, in late 2001, certain subsidiaries of Southern Company, including the Company, were named as defendants in a lawsuit brought in Troup County, Georgia, Superior Court by Interstate Fiber Network, Inc., a subsidiary of telecommunications company ITC DeltaCom, Inc. that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. On August 24, 2010, the defendants filed a motion to dismiss the suit for lack of prosecution. In January 2011, the court indicated that it intended to deny the defendant's motion to dismiss the claim; however, no written order denying the motion has been entered into the record. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Retail Regulatory Matters

Performance Evaluation Plan

The Company's retail base rates are set under the Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi PSC. PEP was designed with the objective that PEP would reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high. PEP is a mechanism for rate adjustments based on three indicators: price, customer satisfaction, and service reliability.

In May 2004, the Mississippi PSC approved the Company's requested changes to PEP, including the use of a forward-looking test year, with appropriate oversight; annual, rather than semi-annual, filings; and certain changes to the performance indicator mechanisms. Rate changes are limited to 4% of retail revenues annually under the revised PEP. PEP will remain in effect until the Mississippi PSC modifies, suspends, or terminates the plan. In the May 2004 order, the Mississippi PSC ordered that the Mississippi Public Utilities Staff and the Company review the operations of the PEP in 2007. By mutual agreement, this review was deferred until 2008 and continued into 2009. In March 2009, concurrent with this review, the annual PEP evaluation filing for 2009 was suspended. In August 2009, the Mississippi Public Utilities Staff and the Company filed a joint report with the Mississippi PSC proposing several changes to the PEP. In November 2009, the Mississippi PSC approved the revised PEP, which resulted in a lower performance incentive under the PEP and therefore smaller and/or less frequent rate changes in the future. In November 2009, the Company resumed annual evaluations and filed its annual PEP filing for 2010 under the revised PEP, which resulted in a lower allowed return on investment but no rate change. On November 15, 2010, the Company filed its annual PEP filing for 2011 under the revised PEP, which indicated a rate increase of 1.936%, or $16.1 million annually. On January 10, 2011, the Mississippi Public Utilities Staff contested the filing. Under the revised PEP, the review of the annual PEP filing must be concluded by the first billing cycle in April 2011. The ultimate outcome of this matter cannot be determined at this time.

In April 2007, the Mississippi PSC issued an order allowing the Company to defer certain reliability-related maintenance costs beginning January 1, 2007 and recover them evenly over a four-year period beginning January 1, 2008. These costs related to maintenance that was needed as follow-up to emergency repairs that were made subsequent to Hurricane Katrina. At December 31, 2007, the Company had incurred and deferred the retail portion of $9.5 million of such costs. At December 31, 2010, the Company had a balance of the deferred retail portion of $2.4 million included in current assets as other regulatory assets.

In December 2007, the Company submitted its annual PEP filing for 2008, which resulted in a rate increase of 1.983% or $15.5 million annually, effective January 2008.

In December 2007, the Company received an order from the Mississippi PSC requiring it to defer $1.4 million associated with the retail portion of certain tax credits and adjustments related to permanent differences pertaining to its 2006 income tax returns filed in September 2007. These tax differences were recorded in a regulatory liability included in the current portion of other regulatory liabilities and were amortized ratably over the 12-month period beginning January 2008. The amortization of $1.4 million is included in income taxes on the statement of income for 2008.

On March 15, 2010, the Company submitted its annual PEP lookback filing for 2009, which recommended no surcharge or refund. On October 26, 2010, the Company and the Mississippi Public Utilities Staff agreed and stipulated that no surcharge or refund is required. On November 2, 2010, the Mississippi PSC accepted the stipulation. On or before March 15, 2011, the Company will submit its annual PEP lookback filing for 2010. The ultimate outcome of this matter cannot now be determined.

System Restoration Rider

The Company is required to make annual SRR filings to determine the revenue requirement associated with the property damage. The purpose of the SRR is to provide for recovery of costs associated with property damage (including certain property insurance and the costs of self insurance) and to facilitate the Mississippi PSC's review of these costs. The Mississippi PSC periodically agrees on SRR revenue levels that are developed based on historical data, expected exposure, type and amount of insurance coverage excluding insurance costs, and other relevant information. The applicable SRR rate level will be adjusted every three years, unless a significant change in circumstances occurs such that the Company and the Mississippi Public Utilities Staff or the Mississippi PSC deems that a more frequent change would be appropriate. The Company will submit annual filings setting forth SRR-related revenues, expenses, and investment for the projected filing period, as well as the true-up for the prior period. As a result of the Mississippi PSC establishing the current SRR calculation in January 2009, the December 2008 retail regulatory liability of $6.8 million was reclassified to the property damage reserve.

In February 2009, the Company submitted its 2009 SRR rate filing with the Mississippi PSC, which proposed that the 2009 SRR rate level remain at zero and the Company be allowed to accrue approximately $4.0 million to the property damage reserve in 2009. In September 2009, the Mississippi PSC issued an order requiring the Company to develop SRR factors designed to reduce SRR revenue by approximately $1.5 million from November 2009 to March 2010 under the new rate. On January 29, 2010, the Company submitted its 2010 SRR rate filing with the Mississippi PSC, which allowed the Company to accrue $3.1 million to the property damage reserve in 2010. On January 31, 2011, the Company submitted its 2011 SRR rate filing with the Mississippi PSC, which proposed that the Company be allowed to accrue approximately $3.6 million to the property damage reserve in 2011. The ultimate outcome of this matter cannot be determined at this time.

Environmental Compliance Overview Plan

On February 14, 2011, the Company submitted its 2011 ECO Plan notice which proposed an immaterial decrease in annual revenues for the Company. In addition, the Company proposed to change the ECO Plan collection period to more appropriately match ECO revenues with ECO expenditures. The ultimate outcome of this matter cannot be determined at this time.

On February 12, 2010, the Company submitted its 2010 ECO Plan notice which proposed an increase in annual revenues for the Company of approximately $3.9 million. Due to changes in ECO Plan cost projections, on August 20, 2010, the Company submitted a revised 2010 ECO Plan which reduced the requested increase in annual revenues to $1.7 million. In its 2010 ECO Plan filing, the Company proposed to change the true-up provision of the ECO Plan rate schedule to consider actual revenues collected in addition to actual costs. Hearings on the 2010 ECO Plan were held with the Mississippi PSC on October 5, 2010. On October 25, 2010, the Mississippi PSC held a public meeting to discuss the 2010 ECO Plan and issued an order approving the revised 2010 ECO Plan with the new rates effective in November 2010. The Company and the Mississippi Public Utilities Staff jointly agreed to defer the decision on the change in the true-up provision of the ECO Plan rate schedule. As a result of the change in the collection period requested in the Company's 2011 ECO filing, the Company has decided not to pursue the change in the true-up provision.

In February 2009, the Company submitted its 2009 ECO Plan notice which proposed an increase in annual revenues for the Company of approximately $1.5 million. In June 2009, the Mississippi PSC approved the ECO Plan with the new rates effective June 2009. In February 2008, the Company filed with the Mississippi PSC its annual ECO Plan evaluation for 2008. After the filing of the ECO Plan evaluation in February 2008, the regulations addressing mercury emissions were altered by a decision issued by the U.S. Court of Appeals for the District of Columbia Circuit in February 2008. In April 2008, the Company filed with the Mississippi PSC a supplemental ECO Plan evaluation in which the projects included in the ECO Plan evaluation in February 2008 being undertaken primarily for mercury control were removed. In this supplemental ECO Plan filing, the Company requested a 15 cent per 1,000 kilowatt-hour decrease for retail residential customers. The Mississippi PSC approved the supplemental ECO Plan evaluation in June 2008, with the new rates effective in June 2008.

On July 22, 2010, the Company 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 the Company and Gulf Power, 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 Mississippi PSC, is expected to be recovered through the ECO Plan. Hearings on the certificate request were held by the Mississippi PSC on January 25, 2011 with a final order expected by February 28, 2011. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; such filing occurred on November 15, 2010. The Mississippi PSC approved the retail fuel cost recovery factor on December 7, 2010, with the new rates effective in January 2011. The retail fuel cost recovery factor will result in an annual decrease in an amount equal to 5.0% of total 2010 retail revenue. At December 31, 2010, the amount of over recovered retail fuel cost included in the balance sheets was $55.2 million compared to $29.4 million at

December 31, 2009. The Company also has a wholesale Municipal and Rural Associations (MRA) and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2011, the wholesale MRA fuel rate decreased, resulting in an annual decrease in an amount equal to 3.5% of total 2010 MRA revenue. Effective February 1, 2011, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 7.0% of total 2010 MB revenue. At December 31, 2010, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $17.5 million and $4.4 million compared to $16.8 million and $2.4 million, respectively, at December 31, 2009. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, this decrease to the billing factor will have no significant effect on the Company's revenues or net income, but will decrease annual cash flow.

In October 2010, the Mississippi PSC engaged an independent professional audit firm to conduct an audit of the Company's fuel-related expenditures included in the retail fuel adjustment clause and ECM for 2010. The audit is scheduled to be completed in 2011. The ultimate outcome of this matter cannot be determined at this time. A similar audit was conducted beginning in August 2009 for the years 2009 and 2008. The audit was completed in December 2009 with no audit findings.

In October 2008, the Mississippi PSC opened a docket to investigate and review interest and carrying charges under the fuel adjustment clause for utilities within the State of Mississippi including the Company. In March 2009, the Mississippi PSC issued an order to apply the prime rate in calculating the carrying costs on the retail over or under recovery balances related to fuel cost recovery. In May 2009, the Company filed the carrying cost calculation methodology as part of its compliance filing.

Storm Damage Cost Recovery

In August 2005, Hurricane Katrina hit the Gulf Coast of the U.S. and caused significant damage within the Company's service area. The estimated total storm restoration costs relating to Hurricane Katrina through December 31, 2007 of $302.4 million, which was net of expected insurance proceeds of approximately $77 million, without offset for the property damage reserve of $3.0 million, was affirmed by the Mississippi PSC in June 2006, and the Company was ordered to establish a regulatory asset for the retail portion. The Mississippi PSC issued an order directing the Company to file an application with the MDA for a Community Development Block Grant (CDBG). In October 2006, the Company received from the MDA a CDBG in the amount of $276.4 million, which was allocated to both the retail and wholesale jurisdictions. In the same month, the Mississippi PSC issued a financing order that authorized the issuance of system restoration bonds for the remaining $25.2 million of the retail portion of storm recovery costs not covered by the CDBG. These funds were received in June 2007. The Company affirmed the $302.4 million total storm costs incurred as of December 31, 2007. In March 2009, the Company filed with the Mississippi PSC its final accounting of the restoration cost relating to Hurricane Katrina and the storm operations center. The final net retail receivable of approximately $3.2 million is expected to be recovered in 2011.

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 $4.7 million for the Company. Although Internal Revenue Service (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.

Integrated Coal Gasification Combined Cycle

In January 2009, the Company filed for a Certificate of Public Convenience and Necessity (CPCN) with the Mississippi PSC to allow the acquisition, construction, and operation of the IGCC project located in Kemper County, Mississippi. The Kemper IGCC would utilize an IGCC technology with an output capacity of 582 megawatts (MWs). The estimated cost of the plant is $2.4 billion, net of $245 million of grants awarded to the project by the DOE under the CCPI2. The plant will use locally mined lignite (an abundant, lower heating value coal) from a proposed mine adjacent to the plant as fuel. In conjunction with the plant, the Company will own a lignite mine and equipment and will acquire mineral reserves located around the plant site in Kemper County. The estimated capital cost of the mine is approximately $214 million. On May 27, 2010, the Company executed a 40-year management fee contract with

Liberty Fuels Company, LLC, a subsidiary of The North American Coal Corporation, which will develop, construct, and manage the mining operations. The agreement is effective June 1, 2010 through the end of the mine reclamation. The plant, subject to federal and state reviews and certain regulatory approvals, is expected to begin commercial operation in May 2014. As part of its filing, the Company requested certain rate recovery treatment in accordance with the State of Mississippi Baseload Act of 2008 (Baseload Act).

Beginning in December 2006, the Mississippi PSC approved the Company's requested accounting treatment to defer the costs associated with the Company's generation resource planning, evaluation, and screening activities as a regulatory asset. In April 2009, the Company received an accounting order from the Mississippi PSC directing the Company to continue to charge all generation resource planning, evaluation, and screening costs to regulatory assets including those costs associated with activities to obtain a CPCN and costs necessary and prudent to preserve the availability, economic viability, and/or required schedule of the Kemper IGCC generation resource planning, evaluation, and screening activities until the Mississippi PSC makes findings and determination as to the recovery of the Company's prudent expenditures.

In June 2009, the Mississippi PSC issued an order initiating an evaluation of the Company's CPCN petition and established a two-phase procedural schedule to evaluate the need for and the resources and cost of the new generating capacity separately. In November 2009, the Mississippi PSC issued an order that found the Company had demonstrated a need for additional capacity of approximately 304 MWs to 1,276 MWs based on an analysis of expected load forecasts, costs, and anticipated retirements. Hearings related to the appropriate resource to meet that need as well as cost recovery of that resource through application of the Baseload Act were held in February 2010.

On April 29, 2010, the Mississippi PSC issued an order finding that the Company's application to acquire, construct, and operate the plant did not satisfy the requirement of public convenience and necessity in the form that the project and the related cost recovery were originally proposed by the Company, unless the Company accepted certain conditions on the issuance of the CPCN, including a cost cap of approximately $2.4 billion. The April 2010 order also approved recovery of $46 million out of $50.5 million in prudent pre-construction costs incurred through March 2009. The remaining $4.5 million is associated with overhead costs and variable pay of SCS, which were recommended for exclusion from pre-construction costs by a consultant hired by the Mississippi Public Utilities Staff. An additional $3.5 million was incurred for costs of this type from March 2009 through May 2010. The remaining $4.5 million, as well as additional pre-construction amounts incurred during the generation screening and evaluation process through May 2010, will be reviewed and addressed in a future proceeding.

On May 10, 2010, the Company filed a motion in response to the April 29, 2010 order of the Mississippi PSC relating to the Kemper IGCC, or in the alternative, for alteration or rehearing of such order.

On May 26, 2010, the Mississippi PSC issued an order revising its findings from the April 29, 2010 order. Among other things, the Mississippi PSC's May 26, 2010 order (1) approved an alternate construction cost cap of up to $2.88 billion (and any amounts that fall within specified exemptions from the cost cap; such exemptions include the costs of the lignite mine and equipment and the carbon dioxide pipeline facilities), subject to determinations by the Mississippi PSC that such costs in excess of $2.4 billion are prudent and required by the public convenience and necessity; (2) provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's proposal; and (3) approved financing cost recovery on construction work in progress (CWIP) balances under the Baseload Act, which provides for the accrual of AFUDC in 2010 and 2011 and recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of CWIP allowed is (i) reduced by the amount of state and federal government construction cost incentives received by the Company in excess of $296 million to the extent that such amount increases cash flow for the pertinent regulatory period and (ii) justified by a showing that such CWIP allowance will benefit customers over the life of the plant). The Mississippi PSC order established periodic prudence reviews during the annual CWIP review process. More frequent prudence determinations may be requested at a later time. On May 27, 2010, the Company filed a motion with the Mississippi PSC accepting the conditions contained in the order. On June 3, 2010, the Mississippi PSC issued the final certificate order which granted the Company's motion and issued the CPCN authorizing acquisition, construction, and operation of the plant. As of May 31, 2010, construction related screening costs of $116.2 million were reclassified to CWIP while the non-capital related costs of $11.2 million and $0.6 million were classified in other regulatory assets and other deferred charges, respectively, and $1.0 million was previously expensed.

Pursuant to the Mississippi PSC's order granting the CPCN for the Kemper IGCC, the Mississippi PSC and Mississippi Public Utilities Staff has hired various consultants to assist both organizations in monitoring the construction of the plant.

On June 17, 2010, the Mississippi Chapter of the Sierra Club (Sierra Club) filed an appeal of the Mississippi PSC's June 3, 2010 decision to grant the CPCN for the plant with the Chancery Court of Harrison County, Mississippi (Chancery Court). Subsequently, on July 6, 2010, the Sierra Club also filed an appeal directly with the Mississippi Supreme Court. On July 20, 2010, the Chancery Court issued a stay of the proceeding pending the resolution of the jurisdictional issues raised in a motion filed by the Company on July 16, 2010 to confirm jurisdiction in the Mississippi Supreme Court. On October 7, 2010, the Mississippi Supreme Court denied the Company's motion and dismissed the Sierra Club's direct appeal. The appeal will now proceed in the Chancery Court. On December 22, 2010, the Chancery Court denied the Company's motion to dismiss. A decision on the Sierra Club's appeal from the Chancery court is expected in March 2011.

On November 12, 2010, the Company filed a petition with the Mississippi PSC requesting an accounting order that would establish regulatory assets for certain non-capital costs related to the Kemper IGCC. In its petition, the Company outlined three categories of non-capital, plant-related costs that it proposed to defer in a regulatory asset until construction is complete and a cost recovery mechanism is established for the plant: (1) regulatory costs; (2) costs of executing non-construction contracts; and (3) other project-related costs not permitted to be capitalized.

The Company filed an application in June 2006 with the U.S. Department of Energy (DOE) for certain tax credits available to projects using clean coal technologies under the Energy Policy Act of 2005. The DOE subsequently certified the plant, and in November 2006, the IRS allocated Internal Revenue Code Section 48A tax credits (Phase I) of $133 million to the Company. In May 2009, the Company received notification from the IRS formally certifying these tax credits. In addition, the Company filed an application in November 2009 with the DOE and in December 2009 with the IRS for certain tax credits (Phase II) available to projects using advanced coal technologies under the Energy Improvement and Extension Act of 2008. The DOE subsequently certified the Kemper IGCC, and on April 30, 2010, the IRS allocated $279 million of Phase II tax credits under Section 48A of the Internal Revenue Code to the Company. On September 30, 2010, the Company and the IRS executed the closing agreement for the Phase II tax credits. The Company has secured all environmental reviews and permits necessary to commence construction of the plant and has entered into a binding contract for the steam turbine generator, completing two milestone requirements for these credits. The utilization of Phase I and Phase II credits are dependent upon meeting the IRS certification requirements, including an in-service date no later than May 2014 for the Phase I credits. In order to remain eligible for the Phase II tax credits, the Company plans to capture and sequester (via enhanced oil recovery) at least 65% of the carbon dioxide produced by the plant during operations in accordance with the recapture rules for Section 48A investment tax credits. Through December 31, 2010, the Company received tax benefits of $21.9 million for these tax credits.

In February 2008, the Company requested that the DOE transfer the remaining funds previously granted under the CCPI2 from a cancelled IGCC project of one of Southern Company's subsidiaries that would have been located in Orlando, Florida. In December 2008, an agreement was reached to assign the remaining funds ($270 million) to the Kemper IGCC. On August 19, 2010, the National Environmental Policy Act (NEPA) Record of Decision (ROD) by the DOE for the CCPI2 grants was noted in the Federal Register. The NEPA ROD and its accompanying final environmental impact statement were the final major hurdles necessary for the Company to receive grant funds of $245 million during the construction of the plant and $25 million during the initial operation of the plant. As of December 31, 2010, the Company has received $23.1 million and billed an additional $9.5 million associated with this grant.

In April 2009, the Governor of the State of Mississippi signed into law a bill that will provide an ad valorem tax exemption for a portion of the assessed value of all property utilized in certain electric generating facilities with integrated gasification process facilities. This tax exemption, which may not exceed 50% of the total value of the project, is for projects with a capital investment from private sources of $1 billion or more. The Company expects the Kemper IGCC, including the gasification portion, to be a qualifying project under the law.

On July 27, 2010, the Company and South Mississippi Electric Power Association (SMEPA) entered into an Asset Purchase Agreement whereby SMEPA will purchase an undivided 17.5% interest in the plant. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. On December 2, 2010, the Company and SMEPA filed a Joint Petition with the Mississippi PSC requesting regulatory approval for SMEPA's 17.5% ownership of the Kemper IGCC.

On March 9, 2010, the Mississippi Department of Environmental Quality issued the PSD air permit modification for the plant, which modifies the original PSD air permit issued in October 2008. The Sierra Club has requested a formal evidentiary hearing regarding the issuance of the modified permit.

As of December 31, 2010, the Company had spent a total of $255.1 million on the plant, including regulatory filing costs. Of this total, $207.6 million was included in CWIP (net of $32.7 million of CCPI2 grant funds), $12.3 million was recorded in other regulatory assets, $1.5 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed.

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

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own, as tenants in common, Units 1 and 2 (total capacity of 500 MWs) at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2 (total capacity of 1,000 MWs) at Plant Daniel, which is located in Mississippi and operated by the Company.

At December 31, 2010, the Company's percentage ownership and investment in these jointly owned facilities were as follows:

Generating Plant	Percent Ownership	Gross Investment	Accumulated Depreciation
		(in thousands)	
Greene County			
Units 1 and 2	40%	$ 87,326	$ 45,101
Daniel			
Units 1 and 2	50%	$280,885	$ 140,029

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

5. INCOME TAXES

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

Current and Deferred Income Taxes

Details of the income tax provisions are as follows:

	2010	2009	2008
		(in thousands)	
Federal –			
Current	**$ 5,399**	$77,619	$20,834
Deferred	**35,367**	(32,980)	22,054
	40,766	44,639	42,888
State –			
Current	**3,319**	12,444	2,675
Deferred	**2,190**	(6,869)	2,786
	5,509	5,575	5,461
Total	**$46,275**	$50,214	$48,349

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	**$321,918**	$279,683
Basis differences	**1,499**	19,730
Energy cost management clause under recovered	**10,216**	25,232
Regulatory assets associated with asset retirement obligations	**7,338**	6,876
Regulatory assets associated with employee benefit obligations	**35,021**	43,535
Regulatory assets associated with the Kemper IGCC	**4,640**	-
OCI	**1**	-
Other	**40,416**	21,679
Total	**421,049**	396,735
Deferred tax assets –		
Federal effect of state deferred taxes	**11,323**	8,979
Fuel clause over recovered	**39,779**	44,009
Other property basis differences	**3,013**	7,367
Pension and other benefits	**53,213**	64,553
Property insurance	**23,880**	22,365
Unbilled fuel	**16,703**	12,194
Long-term service agreement	**4,740**	21,317
Asset retirement obligations	**7,338**	6,876
Other	**21,614**	18,246
Total	**181,603**	205,906
Total deferred tax liabilities, net	**239,446**	190,829
Portion included in (accrued) prepaid income taxes, net	**42,521**	32,237
Accumulated deferred income taxes	**$281,967**	$223,066

At December 31, 2010, the tax-related regulatory assets and liabilities were $19.2 million and $13.2 million, respectively. 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 interest. In 2010, the Company deferred $5.5 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 income tax expense over 10 years beginning January 1, 2011, as approved by the Mississippi PSC for the retail portion and over five years for the wholesale portion, as approved by the FERC. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.3 million, $1.2 million, and $1.2 million for 2010, 2009, and 2008, respectively. At December 31, 2010, all investment tax credits available to reduce federal income taxes payable had been utilized. In 2010, the Company began recognizing investment tax credits associated with the construction expenditures related to the Kemper IGCC. At December 31, 2010, the Company had $22.2 million in unamortized investment tax credits associated with this facility.

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 tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2010	2009	2008
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.8**	2.7	2.6
Non-deductible book depreciation	**0.3**	0.3	0.3
Medicare subsidy	**(0.2)**	(0.4)	(0.5)
Amortization of permanent tax items[a]	**0.0**	0.0	(0.7)
AFUDC-equity	**(1.0)**	(0.1)	0.0
Other	**(0.8)**	(0.8)	(1.2)
Effective income tax rate	**36.1%**	36.7%	35.5%

[a]Amortization of Regulatory Liability Tax Credits. See Note 3 under "Retail Regulatory Matters - Performance Evaluation Plan."

The Company's 2010 effective tax rate decreased from 2009 primarily due to the increase in AFUDC equity related to increased construction expenditures.

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is 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 $1.3 million, resulting in a balance of $4.3 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	**$3,026**	$1,772	$ 935
Tax positions from current periods	**868**	1,309	653
Tax positions from prior periods	**611**	(55)	265
Reductions due to settlements	**-**	-	(81)
Reductions due to expired statute of limitations	**(217)**	-	-
Balance at end of year	**$4,288**	$3,026	$1,772

The tax positions increase from current periods relate primarily to 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, is as follows:

	2010	2009	2008
		(in thousands)	
Tax positions impacting the effective tax rate	**$3,058**	$3,026	$1,772
Tax positions not impacting the effective tax rate	**1,230**	-	-
Balance of unrecognized tax benefits	**$4,288**	$3,026	$1,772

The tax positions impacting the effective tax rate primarily relate to the production activities deduction tax position and other miscellaneous uncertain tax positions. 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	**$230**	$203	$106
Interest reclassified due to settlements	**-**	-	(17)
Interest accrued during the year	**183**	27	114
Balance at end of year	**$413**	$230	$203

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 possible conclusion or settlement of state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all 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

Bank Term Loans

In September 2010, the Company entered into a one-year $125 million aggregate principal amount long-term floating rate bank loan that bears interest based on the one-month London Interbank Offered Rate (LIBOR). The proceeds of this loan were used to repay maturing long-term and short-term indebtedness and for other general corporate purposes, including the Company's continuous construction program. In 2008, the Company borrowed $80 million under a three-year term loan agreement that matures in March 2011. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

Senior Notes

In March 2009, the Company issued $125 million of Series 2009A 5.55% Senior Notes due March 1, 2019. Proceeds were used to repay at maturity the Company's $40.0 million aggregate principal amount of Series F Floating Rate Senior Notes due March 9, 2009, to repay a portion of its short-term indebtedness and for general corporate purposes, including the Company's continuous construction program. The Company had a total of $330 million of senior notes outstanding at December 31, 2010 and 2009.

Revenue Bonds

In December 2010, the Company incurred obligations relating to the issuance of $100 million of revenue bonds in two series, each of which is due December 1, 2040. The first series of $50 million was issued with an initial fixed rate of 2.25% through January 14, 2013 and the second series of $50 million was issued with a floating rate. Proceeds from the second series bonds were classified as restricted cash at December 31, 2010 and these bonds were redeemed on February 8, 2011. The proceeds from the first series bonds were used to finance the acquisition and construction of buildings and immovable equipment in connection with the Company's construction of the Kemper IGCC.

Securities Due Within One Year

At December 31, 2010 and 2009, the Company had scheduled maturities of capital leases due within one year of $1.4 million and $1.3 million, respectively. At December 31, 2010, the Company had planned the redemption of the second series revenue bonds issued in December 2010 in the amount of $50.0 million for February 2011. In addition, a long term bank loan of $80 million matures in March 2011 and a $125.0 million term loan matures in September 2011.

Maturities through 2013 applicable to total long-term debt are as follows: $256.4 million in 2011; $0.6 million in 2012; and $50.0 million in 2013. There are no scheduled maturities in 2014 and 2015.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2010 and 2009 was $82.7 million. In September 2008, the Company was required to purchase a total of approximately $7.9 million of variable rate pollution control revenue bonds that were tendered by investors. In December 2008, the bonds were successfully remarketed. On the statement of cash flow for 2008, the $7.9 million is presented as proceeds and redemptions.

Outstanding Classes of Capital Stock

The Company currently has preferred stock (including depositary shares which represent one-fourth of a share of preferred stock) and common stock authorized and outstanding. The preferred stock of the Company contains a feature that allows the holders to elect a majority of the Company's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, this preferred stock is presented as "Cumulative Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The Company's preferred stock and depositary preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary or involuntary dissolution. Certain series of the preferred stock and depositary preferred stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the stock.

Dividend Restrictions

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

Bank Credit Arrangements

At the beginning of 2011, the Company had total unused committed credit agreements with banks of $161 million, all of which expire in 2011. Approximately $41 million of the facilities contain two-year term loan options and $65 million contain one-year term loan options. The Company expects to renew its credit facilities, as needed, prior to expiration.

In connection with these credit arrangements, the Company agrees to pay commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. Commitment fees average less than 3/8 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

The credit arrangements contain covenants that limit the ratio of indebtedness to capitalization (each as defined in the arrangements) to 65%. For purposes of these definitions, indebtedness excludes long-term debt payable to affiliated trusts and, in certain cases, other hybrid securities.

In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2010, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowing.

This $161 million in unused credit arrangements provides required liquidity support to the Company's borrowings through a commercial paper program. At December 31, 2010 and 2009, the Company had no commercial paper outstanding. The credit arrangements also provide support to the Company's variable rate tax-exempt bonds totaling $90.1 million. Subsequent to December 31, 2010, $50.0 million of revenue bonds were redeemed on February 8, 2011, reducing liquidity support to $40.1 million.

During 2010, the maximum amount outstanding for commercial paper was $63.0 million and the average amount outstanding was $12.0 million. During 2009, the maximum amount outstanding for commercial paper was $66.7 million and the average amount outstanding was $15.9 million. The weighted average annual interest rate on commercial paper was 0.3% for 2010 and 0.3% for 2009.

7. COMMITMENTS

Construction Program

The construction program of the Company is currently estimated to include a base level investment of $818 million in 2011, $1.0 billion in 2012, and $878 million in 2013. Included in these estimated amounts are expenditures related to the Kemper IGCC of $665 million, $813 million, and $616 million in 2011, 2012, and 2013, respectively, which are net of SMEPA's 17.5% expected ownership share of the Kemper IGCC of approximately $354 million and $91 million in 2012 and 2013, respectively. Also included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $45 million, $94 million, and $127 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; Mississippi 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. At December 31, 2010, significant purchase commitments were outstanding in connection with the ongoing construction program. Capital improvements to generating, transmission, and distribution facilities, including those to meet environmental standards, will continue. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

Long-Term Service Agreements

The Company has entered into a long-term service agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the leased combined cycle units at Plant Daniel. The LTSA provides that GE will cover 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 units. Scheduled payments to GE under the LTSA, which are subject to price escalation, are made monthly based on estimated operating hours of the units and are recognized as expense based on actual hours of operation. The Company has recognized $12.6 million, $13.3 million, and $9.4 million for 2010, 2009, and 2008, respectively, which is included in other operations and maintenance expense in the statements of income. Remaining payments to GE under the LTSA are currently estimated to total $106.7 million over the next nine years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company also has entered into a LTSA with Alstom Power, Inc. for the purpose of securing maintenance support for its Chevron Unit 5 combustion turbine plant. In summary, the LTSA stipulates that Alstom Power, Inc. will perform all planned maintenance on the covered equipment, which includes the cost of all labor and materials. Alstom Power, Inc is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in the LTSA.

In general, this LTSA is in effect through two major inspection cycles. Scheduled payments to Alstom Power, Inc., which are subject to price escalation, are made at various intervals based on actual operating hours of the unit. Payments to Alstom Power, Inc. under the LTSA are currently estimated to total $17.9 million over the remaining term of the LTSA, which is approximately seven years. However, the LTSA contains various cancellation provisions at the option of the Company. Payments made to Alstom Power, Inc. under the LTSA prior to the performance of any planned maintenance are recorded as a prepayment in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed. After the LTSA expires, the Company expects to replace it with a new contract with similar terms.

Fuel 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.

Total estimated minimum long-term commitments at December 31, 2010 were as follows:

	Commitments	
	Natural Gas	Coal
	(in thousands)	
2011	$180,653	$324,360
2012	138,530	122,400
2013	108,465	23,005
2014	82,367	8,440
2015	94,645	960
2016 and thereafter	162,723	36,480
Total	$767,383	$515,645

Coal commitments include a minimum annual management fee of $38.1 million beginning in 2014 from the executed 40-year management contract with Liberty Fuels, LLC related to the Kemper IGCC. 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

Plant Daniel Combined Cycle Generating Units

In 2001, the Company began the initial 10-year term of the lease agreement for a 1,064-MW natural gas combined cycle generating facility built at Plant Daniel (Facility). The lease arrangement provided a lower cost alternative to its cost based rate regulated customers than a traditional rate base asset. See Note 3 under "Retail Regulatory Matters – Performance Evaluation Plan" for a description of the Company's formulary rate plan.

In 2003, the Facility was acquired by Juniper Capital L.P. (Juniper), whose partners are unaffiliated with the Company. Simultaneously, Juniper entered into a restructured lease agreement with the Company. Juniper has also entered into leases with other parties unrelated to the Company. The assets leased by the Company comprise less than 50% of Juniper's assets. The Company is not required to consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. The lease agreement is treated as an operating lease for accounting purposes as well as for both retail and wholesale rate recovery purposes. For income tax purposes, the Company retains tax ownership. The initial lease term ends in 2011 and the lease includes a purchase and renewal option based on the cost of the Facility at the inception of the lease, which was $370 million. The Company is required to amortize approximately 4% of the initial acquisition cost over the initial lease term. In April 2010, the Company was required to notify the lessor, Juniper, if it intended to terminate the lease at the end of the initial term expiring in October 2011. The Company chose not to give notice to terminate the lease. The Company has the option to purchase the Plant Daniel combined cycle generating units for approximately $354 million or renew the lease for approximately $31 million annually for 10 years. The Company will have to provide notice of its intent to either renew the lease or purchase the facility by July 2011. If the lease is renewed, the agreement calls for the Company to amortize an additional 17% of the initial completion cost over the renewal period. Upon termination of the lease, at the Company's option, it may either exercise its purchase option or the Facility can be sold to a third party. If the Company does not exercise either its purchase option or its renewal option, the Company could lose its rights to some or all of the 1,064 MWs of capacity at that time. The ultimate outcome of this matter cannot be determined at this time.

The lease provides for a residual value guarantee, approximately 73% of the acquisition cost, by the Company that is due upon termination of the lease in the event that the Company does not renew the lease or purchase the Facility and that the fair market value is less than the unamortized cost of the Facility. A liability of approximately $2 million, $3 million, and $5 million for the fair market value of this residual value guarantee is included in the balance sheets at December 31, 2010, 2009, and 2008, respectively. Lease expenses were $26 million, $26 million, and $26 million in 2010, 2009, and 2008, respectively.

The Company estimates that its annual amount of future minimum operating lease payments under this arrangement, exclusive of any payment related to the residual value guarantee or purchase or renewal options, as of December 31, 2010, are as follows:

Minimum Lease Payments	
	(in thousands)
2011	$28,291
2012 and thereafter	-
Total commitments	$28,291

Other Operating Leases

The Company and Gulf Power have jointly entered into operating lease agreements for the use of 745 aluminum railcars. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value, or to renew the leases at the end of the lease term. The Company also has multiple operating lease agreements for the use of additional railcars that do not contain a purchase option. All of these leases are for the transport of coal to Plant Daniel.

The Company's share (50%) of the leases, charged to fuel stock 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.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plants Daniel and Watson and operating leases for barges and tow/shift boats for the transport of coal at Plant Watson. The Company's share (50% at Plant Daniel and 100% at Plant Watson) of the leases for fuel handling was charged to fuel handling expense in the amount of $0.7 million in 2010 and $0.6 million in 2009. The Company's annual lease payments for 2011 through 2014 will average approximately $0.2 million for fuel handling equipment. The Company charged to fuel stock and recovered through fuel cost recovery the barge transportation leases in the amount of $8.4 million in 2010 and $8.4 million in 2009 related to barges and tow/shift boats. The Company's annual lease payments for 2011 through 2014 with respect to these barge transportation leases will average approximately $7.9 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 281 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	1,856,656	$31.83
Granted	361,352	31.19
Exercised	(371,799)	28.86
Cancelled	(2,839)	32.38
Outstanding at December 31, 2010	**1,843,370**	**$32.30**
Exercisable at December 31, 2010	**1,161,617**	**$32.60**

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 $10.9 million and $6.5 million, respectively.

As of December 31, 2010, there was $0.2 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 10 months.

For the years ended December 31, 2010, 2009, and 2008, total compensation cost for stock option awards recognized in income was $0.8 million, $0.9 million, and $0.7 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.3 million, respectively.

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

The total intrinsic value of options exercised during the years ended December 31, 2010, 2009, and 2008 was $2.7 million, $0.4 million, and $3.7 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.0 million, $0.2 million, and $1.4 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 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 the 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, 39,883 performance share units were granted to the Company's employees with a weighted-average grant date fair value of $30.13. During 2010, 2,902 performance share units were forfeited by the Company's employees resulting in 36,981 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 $0.7 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			
At 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	$ -	$2,075	$ -	$ 2,075
Foreign currency derivatives	-	3,419	-	3,419
Cash equivalents	160,200	-	-	160,200
Total	$160,200	$5,494	$ -	$165,694
Liabilities:				
Energy-related derivatives	$ -	$45,845	$ -	$ 45,845
Foreign currency derivatives	-	95	-	95
Total	$ -	$45,940	$ -	$ 45,940

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 LIBOR. Foreign currency derivatives are also standard over-the-counter financial products valued using the market approach using inputs from observable market sources. 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	$160,200	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 Securities and Exchange Commission 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	**$716,399**	**$738,211**
2009	$491,410	$497,933

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, interest rate risk, and occasionally foreign currency 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 Mississippi PSC, through the use of financial derivative contracts, and recently has started using significantly more 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 or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

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

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 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 millions)		
24.04	2015	-

* mmBtu - million British thermal units

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2011 are immaterial.

Foreign Currency Derivatives

The Company may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge 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. Any ineffectiveness is recorded directly to earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2010, the following foreign currency derivatives were outstanding:

	Notional Amount	Forward Rate	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2010
	(in millions)			*(in thousands)*
Fair value hedges of firm commitments				
	EUR 41.1	1.256 Dollars per Euro*	Various through July 2012	$3,324

* Weighted Average

Derivative Financial Statement Presentation and Amounts

At December 31, 2010 and 2009, the fair value of energy-related derivatives and foreign currency derivatives was 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	**$ 830**	$446	Liabilities from risk management activities	**$27,459**	$19,454
	Other deferred charges and assets	**1,238**	105	Other deferred credits and liabilities	**18,386**	22,843
Total derivatives designated as hedging instruments for regulatory purposes		**$2,068**	$551		**$45,845**	$42,297
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	**$ 3**	$ -	Liabilities from risk management activities	**$ -**	$ -
Foreign currency derivatives:	Other current assets	**2,403**	-	Liabilities from risk management activities	**66**	-
	Other deferred charges and assets	**1,016**	-	Other deferred credits and liabilities	**29**	-
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$3,422**	$ -		**$ 95**	$ -
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ 4**	$ 12	Liabilities from risk management activities	**$ -**	$ -
Total		**$5,494**	$563		**$45,940**	$42,297

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	**$(27,459)**	$(19,454)	Other regulatory liabilities, current	**$ 830**	$446
	Other regulatory assets, deferred	**(18,386)**	(22,843)	Other regulatory liabilities, deferred	**1,238**	105
Total energy-related derivative gains (losses)		**$(45,845)**	$(42,297)		**$2,068**	$551

For the years ended December 31, 2010, 2009, and 2008, the pre-tax effect of energy-related 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)*	
Energy-related derivatives	**$3**	$ -	$(929)	Fuel	**$ -**	$ -	$ -

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.

For the twelve months ended December 31, 2010, the pre-tax gains from foreign currency derivatives designated as fair value hedging instruments on the Company's statements of income were $3.3 million. These amounts were offset with changes in the fair value of the purchase commitment related to equipment purchases. Therefore, there is no impact on the Company's statements of income.

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 $4.9 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 Preferred Stock
		(in thousands)	
March 2010	**$283,638**	**$30,026**	**$15,253**
June 2010	**276,821**	**29,535**	**15,219**
September 2010	**327,083**	**55,033**	**33,593**
December 2010	**255,526**	**28,224**	**16,152**
March 2009	$268,723	$31,418	$17,971
June 2009	286,681	40,899	21,933
September 2009	330,680	63,075	34,898
December 2009	263,337	20,665	10,165

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

SELECTED FINANCIAL AND OPERATING DATA 2006-2010

Mississippi Power Company 2010 Annual Report

	2010	2009	2008	2007	2006
Operating Revenues (in thousands)	**$1,143,068**	$1,149,421	$1,256,542	$1,113,744	$1,009,237
Net Income after Dividends on Preferred Stock (in thousands)	**$80,217**	$84,967	$85,960	$84,031	$82,010
Cash Dividends on Common Stock (in thousands)	**$68,600**	$68,500	$68,400	$67,300	$65,200
Return on Average Common Equity (percent)	**11.49**	13.12	13.75	13.96	14.25
Total Assets (in thousands)	**$2,476,321**	$2,072,681	$1,952,695	$1,727,665	$1,708,376
Gross Property Additions (in thousands)	**$340,162**	$95,573	$139,250	$114,927	$127,290
Capitalization (in thousands)**:**					
Common stock equity	**$737,368**	$658,522	$636,451	$613,830	$589,820
Redeemable preferred stock	**32,780**	32,780	32,780	32,780	32,780
Long-term debt	**462,032**	493,480	370,460	281,963	278,635
Total (excluding amounts due within one year)	**$1,232,180**	$1,184,782	$1,039,691	$928,573	$901,235
Capitalization Ratios (percent)**:**					
Common stock equity	**59.8**	55.6	61.2	66.1	65.4
Redeemable preferred stock	**2.7**	2.8	3.2	3.5	3.6
Long-term debt	**37.5**	41.6	35.6	30.4	31.0
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end)**:**					
Residential	**151,944**	151,375	152,280	150,601	147,643
Commercial	**33,121**	33,147	33,589	33,507	32,958
Industrial	**504**	513	518	514	507
Other	**187**	180	183	181	177
Total	**185,756**	185,215	186,570	184,803	181,285
Employees (year-end)	**1,280**	1,285	1,317	1,299	1,270

	2010	2009	2008	2007	2006
Operating Revenues (in thousands):					
Residential	**$256,994**	$245,357	$248,693	$230,819	$214,472
Commercial	**266,406**	269,423	271,452	247,539	215,451
Industrial	**267,588**	269,128	258,328	242,436	211,451
Other	**6,924**	7,041	6,961	6,420	5,812
Total retail	**797,912**	790,949	785,434	727,214	647,186
Wholesale - non-affiliates	**287,917**	299,268	353,793	323,120	268,850
Wholesale - affiliates	**41,614**	44,546	100,928	46,169	76,439
Total revenues from sales of electricity	**1,127,443**	1,134,763	1,240,155	1,096,503	992,475
Other revenues	**15,625**	14,658	16,387	17,241	16,762
Total	**$1,143,068**	$1,149,421	$1,256,542	$1,113,744	$1,009,237
Kilowatt-Hour Sales (in thousands):					
Residential	**2,296,157**	2,091,825	2,121,389	2,134,883	2,118,106
Commercial	**2,921,942**	2,851,248	2,856,744	2,876,247	2,675,945
Industrial	**4,466,560**	4,329,924	4,187,101	4,317,656	4,142,947
Other	**38,570**	38,855	38,886	38,764	36,959
Total retail	**9,723,229**	9,311,852	9,204,120	9,367,550	8,973,957
Wholesale - non-affiliates	**4,284,289**	4,651,606	5,016,655	5,185,772	4,624,092
Wholesale - affiliates	**774,375**	839,372	1,487,083	1,026,546	1,679,831
Total	**14,781,893**	14,802,830	15,707,858	15,579,868	15,277,880
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.19**	11.73	11.72	10.81	10.13
Commercial	**9.12**	9.45	9.50	8.61	8.05
Industrial	**5.99**	6.22	6.17	5.61	5.10
Total retail	**8.21**	8.49	8.53	7.76	7.21
Wholesale	**6.51**	6.26	6.99	5.94	5.48
Total sales	**7.63**	7.67	7.90	7.04	6.50
Residential Average Annual Kilowatt-Hour Use Per Customer	**15,130**	13,762	13,992	14,294	14,480
Residential Average Annual Revenue Per Customer	**$1,693**	$1,614	$1,640	$1,545	$1,466
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**3,156**	3,156	3,156	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,792**	2,392	2,385	2,294	2,204
Summer	**2,638**	2,522	2,458	2,512	2,390
Annual Load Factor (percent)	**57.9**	60.7	61.5	60.9	61.3
Plant Availability Fossil-Steam (percent)	**93.8**	94.1	91.6	92.2	81.1
Source of Energy Supply (percent):					
Coal	**43.0**	40.0	58.7	60.0	63.1
Oil and gas	**41.9**	43.6	28.6	27.1	26.1
Purchased power -					
From non-affiliates	**1.3**	3.3	4.4	3.0	3.5
From affiliates	**13.8**	13.1	8.3	9.9	7.3
Total	**100.0**	100.0	100.0	100.0	100.0

[This page intentionally left blank]

SOUTHERN POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Southern Power Company and Subsidiary Companies 2010 Annual Report

The management of Southern 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.

Oscar C. Harper, IV
President and Chief Executive Officer

Michael W. Southern
Senior Vice President and Chief Financial Officer

February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Southern Power Company

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2010 and 2009, and the related consolidated 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 consolidated financial statements (pages II-434 to II-456) present fairly, in all material respects, the financial position of Southern Power Company and Subsidiary Companies at December 31, 2010 and 2009, and the results of their operations and their 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.

Atlanta, Georgia
February 25, 2011

OVERVIEW

Business Activities

Southern Power Company and its wholly-owned subsidiaries (the Company) construct, acquire, own, and manage generation assets and sell electricity at market-based prices in the wholesale market. The Company continues to execute its strategy through a combination of acquiring and constructing new power plants and by entering into power purchase agreements (PPAs) with investor owned utilities, independent power producers, municipalities, and electric cooperatives. In general, the Company has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities.

The Company is continuing construction of an electric generating plant in Cleveland County, North Carolina. This plant will consist of four combustion turbine natural gas generating units with a total expected generating capacity of 720 megawatts (MW). The units are expected to begin commercial operation in 2012. The Company has entered into long-term PPAs for 540 MWs of the generating capacity of the plant.

The Company is also continuing construction of the Nacogdoches biomass generating plant near Sacul, Texas with an estimated capacity of 100 MWs. The generating plant will be fueled from wood waste. Construction commenced in late 2009 and the plant is expected to begin commercial operation in 2012. The entire output of the plant will be sold under a long-term PPA.

As of December 31, 2010, the Company had units totaling 7,880 MWs nameplate capacity in commercial operation. The weighted average duration of the Company's wholesale contracts exceeds 11.5 years, which reduces remarketing risk. The Company's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets. See FUTURE EARNINGS POTENTIAL herein for additional information.

Key Performance Indicators

To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company focuses on several key performance indicators. These indicators include peak season equivalent forced outage rate (EFOR) and net income. Peak season EFOR defines the hours during peak demand times when the Company's generating units are not available due to forced outages (the lower the better). Net income is the primary measure of the Company's financial performance. The Company's actual performance in 2010 did not meet targets in these key performance areas. The Company did not meet peak season EFOR targets due to unplanned outages at Plant Stanton and Plant Harris. See RESULTS OF OPERATIONS herein for additional information on the Company's net income for 2010.

Earnings

The Company's 2010 net income was $130.0 million, a $25.8 million decrease over 2009. This decrease was primarily due to higher operations and maintenance expenses, higher depreciation and amortization, and profit recognized in 2009 on a construction contract with the Orlando Utilities Commission (OUC) whereby the Company provided engineering, procurement, and construction services to build a combined cycle unit for the OUC. These decreases were partially offset by lower interest expense, net of amounts capitalized.

The Company's 2009 net income was $155.9 million, an $11.5 million increase over 2008. This increase was primarily due to increased margins associated with the operation of Plant Franklin Unit 3 for all of 2009, increased generation from the Company's combined cycle units due to lower natural gas prices, and profit recognized under a construction contract with the OUC. These favorable impacts were partially offset by a loss recognized on the transfer of DeSoto County Generating Company, LLC (DeSoto) to Broadway Gen Funding, LLC (Broadway) in December 2009, gains recognized in income in 2008 related to the sale of an undeveloped tract of land in Orange County, Florida to the OUC, and the receipt of a fee for participating in an asset auction as an unsuccessful bidder. Additionally, depreciation increased due to the completion of Plant Franklin Unit 3 in June 2008 and an increase in depreciation rates. Interest expense increased due to a reduction of capitalized interest as a result of the completion of Plant Franklin Unit 3 in June 2008.

The Company's 2008 net income was $144.4 million, a $12.7 million increase over 2007. This increase was primarily due to increased capacity sales to requirements service customers, market sales of uncontracted generating capacity, a gain on the sale of an undeveloped tract of land in 2008, a loss on the gasifier portion of the integrated coal gasification combined cycle (IGCC) project in 2007, and the receipt of a fee for participating in an asset auction in 2008 as an unsuccessful bidder. These increases were partially offset by transmission service expenses and tariff penalties incurred in 2008, timing of plant maintenance activities, increased general and administrative expenses associated with the implementation of the Federal Energy Regulatory Commission (FERC) separation order, and increased depreciation associated with Plant Oleander Unit 5 and Plant Franklin Unit 3 being placed into commercial operation in December 2007 and June 2008, respectively.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year		
	2010	**2010**	2009	2008
		(in millions)		
Operating revenues	**$ 1,129.1**	**$ 182.5**	$ (366.9)	$ 341.5
Fuel	**391.5**	**159.1**	(192.3)	186.1
Purchased power	**170.1**	**26.1**	(184.0)	128.1
Other operations and maintenance	**147.4**	**10.8**	(11.1)	12.7
Loss (gain) on sale of property	**0.5**	**(4.5)**	11.0	(6.0)
Loss on IGCC project	**-**	**-**	-	(17.6)
Depreciation and amortization	**119.0**	**20.9**	9.6	14.5
Taxes other than income taxes	**17.8**	**0.9**	(0.8)	2.0
Total operating expenses	**846.3**	**213.3**	(367.6)	319.8
Operating income	**282.8**	**(30.8)**	0.7	21.7
Interest expense	**76.1**	**(8.9)**	1.8	4.0
Profit recognized on construction contract	**0.5**	**(12.8)**	13.3	-
Other income (expense), net of amounts capitalized	**(0.4)**	**-**	(8.0)	4.3
Income taxes	**76.8**	**(8.9)**	(7.3)	9.3
Net income	**$ 130.0**	**$ (25.8)**	$ 11.5	$ 12.7

Operating Revenues

Operating revenues in 2010 were $1.1 billion, a $182.5 million (19.3%) increase from 2009. This increase was primarily due to a $377.2 million increase in energy and capacity revenues under new and existing PPAs, $80.8 million associated with higher revenues from energy sales that were not covered by PPAs due to more favorable weather in 2010 compared to 2009, and a $46.8 million increase in revenues from power sales under the Intercompany Interchange Contract (IIC). These increases were partially offset by a $321.4 million decrease in energy and capacity revenues associated with the expiration of PPAs in December 2009 and May 2010.

Operating revenues in 2009 were $946.7 million, a $366.9 million (27.9%) decrease from 2008. This decrease was primarily due to lower natural gas prices that reduced energy revenues. This decrease was partially offset by increased capacity and energy revenues from the operation of Plant Franklin Unit 3 and a PPA relating to four units at Plant Dahlberg that began in June 2009.

Operating revenues in 2008 were $1.31 billion, a $341.5 million (35.1%) increase from 2007. This increase was primarily due to increased short-term energy revenues from uncontracted generating units, increased energy revenues due to higher natural gas prices, and increased revenues from a full year of operations at Plant Oleander Unit 5. These increases were partially offset by decreased demand under existing PPAs due to less favorable weather in 2008 compared to 2007. The increase in fuel revenues was accompanied by an increase in related fuel costs and did not have a significant impact on net income.

Capacity revenues are an integral component of the Company's PPAs with both affiliate and non-affiliate customers and generally represent the greatest contribution to net income. Energy under the PPAs is generally sold at variable cost or is indexed to published gas indices. Energy revenues also include fees for support services, fuel storage, and unit start charges. Details of these PPA capacity and energy revenues are as follows:

	2010	2009	2008
		(in millions)	
Capacity revenues –			
Affiliates	**$ 190.6**	$ 287.6	$ 279.2
Non-affiliates	**257.4**	185.7	165.2
Total	**448.0**	473.3	444.4
Energy revenues –			
Affiliates	**46.1**	192.8	263.6
Non-affiliates	**399.9**	173.8	249.0
Total	**446.0**	366.6	512.6
Total PPA revenues	**$ 894.0**	$ 839.9	$ 957.0

Wholesale revenues that were not covered by PPAs totaled $228.2 million in 2010, which included $134.0 million of revenues from affiliated companies. Wholesale revenues that were not covered by PPAs totaled $98.9 million in 2009, which included $64.0 million of revenues from affiliated companies. Wholesale revenues that were not covered by PPAs totaled $349.2 million in 2008, which included $95.5 million of revenues from affiliated companies. These wholesale sales were made in accordance with the IIC, as approved by the FERC. These non-PPA wholesale revenues will vary from year to year depending on demand and the availability and cost of generating resources at each company that participates in the centralized operation and dispatch of the Southern Company system fleet of generating plants (power pool).

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's fuel and purchased power expenditures are as follows:

	2010	2009	2008
		(in millions)	
Fuel	**$ 391.5**	$ 232.5	$ 424.8
Purchased power-non-affiliates	**72.7**	79.3	132.2
Purchased power-affiliates	**97.4**	64.6	195.8
Total fuel and purchased power expenses	**$ 561.6**	$ 376.4	$ 752.8

In 2010, total fuel and purchased power expenses increased by $185.2 million (49.2%) compared to 2009. Total fuel and purchased power expenses increased $77.3 million primarily due to an 8.7% increase in the average cost of natural gas and a 36.4% increase in the cost of purchased power and $107.9 million due to an increase in kilowatt-hours (KWH) generated and purchased. In 2009, total fuel and purchased power expenses decreased by $376.4 million (50.0%) compared to 2008. This decrease was driven by a 56.0% decrease in the average cost of natural gas and a 41.3% decrease in the average cost of purchased power. Additionally, purchased power volume decreased 25.2% primarily due to increased generation at the Company's combined cycle units as a result of lower natural gas prices. These decreases were partially offset by a 31.2% increase in generation at the Company's combined cycle units as a result of lower natural gas prices. In 2008, total fuel and purchased power expenses increased by $314.2 million (71.6%) compared to 2007. This increase was driven by a 58.9% increase in generation due to operations at Plant Franklin Unit 3, an 11.9% increase in the average cost of natural gas, and a 107.9% increase in the average cost of purchased power.

In 2010, fuel expense increased by $159.1 million (68.4%) compared to 2009. Fuel expense increased $31.7 million primarily due to an 8.7% increase in the average cost of natural gas and $127.4 million due to an increase in KWHs generated. In 2009, fuel expense decreased by $192.3 million (45.3%) compared to 2008. This decrease was driven by a 56.0% decrease in the average cost of natural gas. This decrease was partially offset by a 31.2% increase in generation at the Company's combined cycle units as a result of lower natural gas prices. In 2008, fuel expense increased by $186.1 million (78.0%) compared to 2007. This increase was driven by a 58.9% increase in generation primarily due to operations at Plant Franklin Unit 3 and an 11.9% increase in the average cost of natural gas.

In 2010, purchased power expense increased $26.1 million (18.1%) compared to 2009. Purchased power expense increased $45.6 million due to an increase in the average cost of purchased power, partially offset by a $19.5 million decrease due to fewer KWHs purchased. In 2009, purchased power expense decreased $184.0 million (56.1%) compared to 2008, primarily due to a 41.3% decrease in the average cost of purchased power. Additionally, purchased power volume in 2009 decreased 25.2% due to increased generation at the Company's combined cycle units as a result of lower natural gas prices. Purchased power expense increased $128.1 million (64.1%) in 2008 when compared to 2007, primarily due to a 107.9% increase in the average cost of purchased power.

The Company's PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in fuel costs is accompanied by an increase or decrease in related fuel revenues and does not have a significant impact on net income. The Company is responsible for the cost of fuel for units that are not covered under PPAs. Power from these units is sold into the market or sold to affiliates under the IIC.

Purchased power expenses will vary depending on demand and the availability and cost of generating resources available throughout the Southern Company system and other contract resources. Load requirements are submitted to the power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by the Company, affiliate-owned generation, or external purchases.

Other Operations and Maintenance Expenses

In 2010, other operations and maintenance expenses increased $10.8 million (7.9%) compared to 2009. This increase was primarily due to $4.1 million of additional expense associated with the passage of healthcare legislation in March 2010 and $4.2 million related to generating plant outages and maintenance, mainly at Plants Stanton, Harris, and Franklin. See FUTURE EARNINGS POTENTIAL – "Legislation – Healthcare Reform" herein for additional information regarding healthcare legislation.

In 2009, other operations and maintenance expenses decreased $11.1 million (7.5%) compared to 2008. This decrease was due primarily to transmission tariff penalties recognized in 2008, reduced transmission expenses due to a decrease in power sales into the market, and the timing of plant outages.

In 2008, other operations and maintenance expenses increased $12.7 million (9.4%) compared to 2007. This increase was due primarily to the timing of plant maintenance activities, transmission tariff penalties, and additional administrative and general expenses as a result of costs incurred to implement the FERC compliance plan. See Note 3 to the financial statements under "FERC Matters" for additional information.

Loss (Gain) on Sale of Property

In December 2009, the Company recorded a loss of $5.0 million on the divestiture of DeSoto.

In January 2008, the Company recorded a gain of $6.0 million on the sale of an undeveloped tract of land.

Loss on IGCC Project

In November 2007, the Company and the OUC mutually agreed to terminate the construction of the gasifier portion of the IGCC project, originally planned as a joint venture; however, the Company continued construction of the gas-fired combined cycle generating facility, owned solely by the OUC. The Company recorded a loss in the fourth quarter 2007 of $17.6 million related to the cancellation of the gasifier portion of the IGCC project. This loss consists of the write-off of construction costs of $14.0 million and an accrual for termination payments of $3.6 million. All termination payments were completed in 2008.

Depreciation and Amortization

In 2010, depreciation and amortization increased $20.9 million (21.3%) compared to 2009. This increase was primarily related to a $6.7 million increase associated with the acquisition of West Georgia Generating Company LLC (West Georgia) and the divestiture of DeSoto in December 2009 which resulted in an increase in property, plant, and equipment of $120.2 million. The increase was also due to $7.5 million of equipment retirements and a $6.5 million increase in depreciation rates related primarily to increased starts and run-hours at the Company's generating plants.

In 2009, depreciation and amortization increased $9.6 million (10.9%) compared to 2008. This increase was primarily due to the completion of Plant Franklin Unit 3 in June 2008 and higher depreciation rates implemented during 2009.

In 2008, depreciation and amortization increased $14.5 million (19.7%) due to the completion of Plant Franklin Unit 3 in June 2008 and higher depreciation rates implemented in January 2008.

See ACCOUNTING POLICIES – "Depreciation" herein for additional information regarding the Company's ongoing review of depreciation estimates. See also Note 1 to the financial statements under "Depreciation" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2010, interest expense, net of amounts capitalized decreased $8.9 million (10.4%) compared to 2009. This decrease was primarily due to $10.5 million of additional capitalized interest associated with the construction of the Cleveland County combustion turbine generating plant and the Nacogdoches biomass plant, partially offset by $0.7 million associated with an increase in interest expense on commercial paper and $0.7 million associated with interest rate swaps on senior notes.

In 2009, interest expense, net of amounts capitalized increased $1.8 million (2.1%) compared to 2008. This increase was primarily due to a $5.5 million decrease in capitalized interest as a result of the completion of Plant Franklin Unit 3 in June 2008, partially offset by a $1.7 million decrease in short-term borrowing levels during 2009 and a decrease in amortization of interest rate derivatives of $2.1 million.

In 2008, interest expense, net of amounts capitalized increased $4.0 million (5.1%) compared to 2007. This increase was primarily the result of a decrease in capitalized interest as a result of the completion of Plant Oleander Unit 5 in December 2007 and Plant Franklin Unit 3 in June 2008, partially offset by a decrease in short-term borrowing levels in 2008.

Profit Recognized on Construction Contract

Profit recognized on the construction contract with the OUC whereby the Company has provided engineering, procurement, and construction services to build a combined cycle unit for the OUC was $0.5 million in 2010 and $13.3 million in 2009. No profit or loss on this contract was recognized in 2008. Construction activities commenced in 2006 and were substantially completed in 2009.

Other Income (Expense), Net

The change in other income (expense), net for 2010 as compared to 2009 was not material.

Other income (expense), net was an expense of $0.4 million in 2009 versus income of $7.6 million in 2008. This change was primarily due to a $6.4 million fee received in 2008 for participating in an asset auction. The Company was not the successful bidder in the asset auction.

Other income (expense), net increased $4.3 million (131.1%) in 2008. This increase was primarily due to a $6.4 million fee received in 2008 for participating in an asset auction. The Company was not the successful bidder in the asset auction.

Income Taxes

In 2010, income taxes decreased $8.9 million (10.4%) compared to 2009. This decrease was primarily due to $12.0 million associated with lower pre-tax earnings and $3.7 million of tax benefits associated with the construction of the Nacogdoches biomass plant. These decreases were partially offset by a $6.7 million increase in Alabama state taxes. Alabama's state tax liability is reduced by a deduction for federal income taxes paid. Due to increased bonus depreciation and incentives associated with new plant construction, the federal tax liability was significantly reduced, resulting in a higher overall state tax expense. Also contributing to the increase in state taxes was the application of the resulting higher state tax rate to the deferred income tax balance.

In 2009, income taxes decreased $7.3 million (7.8%) compared to 2008. This decrease was due to changes in the Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 199 production activities deduction, lower state income taxes, and tax benefits received under convertible investment tax credits (ITCs). Higher pre-tax earnings partially offset these decreases. See Note 5 to the financial statements for additional information.

Income taxes increased $9.3 million (11.2%) in 2008 primarily due to higher pre-tax earnings and changes in the Section 199 production activities deduction.

Effects of Inflation

The Company is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

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 competitive wholesale business. The level of future earnings also depends on numerous factors including the Company's ability to achieve sales growth while containing costs, regulatory matters, creditworthiness of customers, total generating capacity available in the Southeast, the successful remarketing of capacity as current contracts expire, and the Company's ability to execute its acquisition strategy and to construct generating facilities. Other factors that could influence future earnings include weather, demand, generation patterns, and operational limitations. Recessionary conditions have lowered demand and have negatively impacted capacity revenues under the Company's PPAs where the amounts purchased are based on demand. The Company is unable to predict whether demand under these PPAs will return to pre-recession levels. The timing and extent of the economic recovery is uncertain and will impact future earnings.

Power Sales Agreements

The Company's sales are primarily through long-term PPAs. The Company is working to maintain and expand its share of the wholesale market. The Company expects that many areas of the market will need capacity in 2017.

The Company's PPAs consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. The Company typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that the Company serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Company resources not dedicated to serve unit or block sales. The Company has rights to purchase power provided by the requirements customers' resources when economically viable.

The Company has entered into the following PPAs over the past three years:

	Date	MWs	Plant	Contract Term
2010				
City of Seneca	June 2010	30 [h]	Unassigned	7/10-6/15
Georgia Electric Membership Corporation (EMCs) [a]	October 2010[a]	423 [h]	Unassigned	01/15-12/27 [a]
2009				
Municipal Electric Authority of Georgia (MEAG Power) [b]	December 2009	157 [h]	West Georgia	12/09-4/29
Georgia Energy Cooperative, Inc. (GEC) [b]	December 2009	151	West Georgia	6/10-5/30
Austin Energy [c]	October 2009	100	Nacogdoches	6/12-5/32
Seminole Electric Cooperative, Inc. (Seminole) [d]	June 2009	509	Oleander	1/16-5/21
2008				
North Carolina Municipal Power Agency No. 1 (NCMPA1)	December 2008	180	Cleveland	1/12-12/31
North Carolina Electric Membership Corporation (NCEMC)	November 2008	180	Cleveland	1/12-12/36
NCEMC	November 2008	180 [e]	Cleveland	1/12-12/36
EnergyUnited Electric Membership Corporation (EnergyUnited)	November 2008	100	Purchased [f]	1/12-12/21
The Energy Authority, Inc.	August 2008	151	Rowan	1/11-12/14
EMCs [g]	July 2008	360 [h]	Unassigned	1/10-12/34 [g]
Florida Municipal Power Agency (FMPA) [i]	July 2008	85	Stanton	10/13-9/23

(a) These agreements, signed in October and December 2010, are extensions of current agreements with 11 Georgia EMCs. Nine agreements were extended from 2015 through 2024, one agreement was extended from 2018 through 2027, and one agreement was extended from 2018 through 2024.
(b) Assumed contract through the West Georgia acquisition in 2009.
(c) Assumed contract through the Nacogdoches Power LLC acquisition in 2009. Commercial operation of Plant Nacogdoches is expected to begin in June 2012.
(d) This agreement is an extension of the current agreement with Seminole for Plant Oleander.
(e) Power purchases under this agreement will increase over the term of the agreement. 45 MWs will be sold from 2012 through 2016, 90 MWs will be sold from 2017 through 2018, and 180 MWs will be sold from 2019 through 2036.
(f) Power to serve this agreement will be purchased under a third party agreement for resale to EnergyUnited. The purchases will be resold at cost.
(g) These agreements are extensions of current agreements with 10 Georgia EMCs. Eight agreements were extended from 2010 through 2031and two agreements were extended from 2013 through 2034.
(h) Represents average annual capacity purchases.
(i) This agreement is an extension of the current agreement with FMPA for Plant Stanton.

The Company has PPAs with some of Southern Company's traditional operating companies and with other investor owned utilities, independent power producers, municipalities, and electric cooperatives. Although some of the Company's PPAs are with the traditional operating companies, the Company's generating facilities are not in the traditional operating companies' regulated rate bases, and the Company is not able to seek recovery from the traditional operating companies' ratepayers for construction, repair, environmental, or maintenance costs. The Company expects that the capacity payments in the PPAs will produce sufficient cash flows to cover costs, pay debt service, and provide an equity return. However, the Company's overall profit will depend on numerous factors, including efficient operation of its generating facilities and demand under the Company's PPAs.

As a general matter, existing PPAs provide that the purchasers are responsible for either procuring the fuel or reimbursing the Company for the cost of fuel relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for transporting the fuel to the particular generating facility.

Fixed and variable operation and maintenance costs will be recovered through capacity charges based on dollars-per-kilowatt year or energy charges based on dollars-per-MW hour. In general, the Company has long-term service contracts with General Electric and Siemens AG to reduce its exposure to certain operation and maintenance costs relating to such vendors' applicable equipment. See Note 7 to the financial statements under "Long-Term Service Agreements" for additional information.

Many of the Company's PPAs have provisions that require the posting of collateral or an acceptable substitute guarantee in the event that Standard & Poor's, a division of The McGraw Hill Companies, Inc. (S&P), or Moody's Investors Service (Moody's) downgrades the credit ratings of the counterparty to an unacceptable credit rating or if the counterparty is not rated or fails to maintain a minimum coverage ratio. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

The Company has entered into long-term power sales agreements for an average of 79% of its available capacity for the next five years and 68% of its available capacity for the next 10 years.

Environmental Matters

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 possible additional federal or state legislation or regulations related to global climate change, air quality, or other environmental and health concerns could also significantly affect the Company.

New environmental legislation or regulations, such as requirements related to greenhouse gases or changes to existing statutes or regulations, could affect many areas of the Company's operations. While the Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Because the Company's units are newer gas-fired generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal-fired generating facilities or older gas-fired generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts, can, however, increase the cost of siting and operating any type of future electric generating facility. The impact of such statutes and regulations on the Company cannot be determined at this time.

Carbon Dioxide Litigation

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 that 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 a similar case. 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 Kivalina case, 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

Air Quality

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 in which the Company operates generating assets 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.

On April 29, 2010, the EPA issued a proposed Industrial Boiler (IB) Maximum Achievable Control Technology rule that would establish emissions limits for various hazardous air pollutants typically emitted from industrial boilers, including biomass boilers and start-up boilers. The EPA issued the final rules on February 23, 2011 and, at the same time, issued a notice of intent to reconsider the final rules to allow for additional public review and comment. The impact of these regulations will depend on their final form and the outcome of any legal challenges and cannot be determined at this time.

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 natural gas and biomass prices, and cost recovery through PPAs.

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. Also, additional compliance costs could affect results of operations, cash flows, and financial condition if such costs are not recovered through PPAs. Further, higher costs that are recovered through regulated rates at other utilities could contribute to an overall reduction in demand for electricity, which could negatively impact the Company's 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 7 million metric tons. The preliminary estimate of carbon dioxide emissions from these units in 2010 is approximately 9 million metric tons. The level of carbon dioxide emissions from year to year will be dependent on the level of generation, 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, including the construction of the Nacogdoches biomass plant in Sacul, Texas.

Legislation

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. The Company incurred a non-cash write-off of approximately $4 million to expense for the year ended December 31, 2010. 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.

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 assets 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 $6 million for the Company. Although Internal Revenue Service (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.

Convertible Investment Tax Credits

In February 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. The Company is receiving ITCs under the renewable energy incentives related to the Nacogdoches biomass facility which will have a material impact on cash flows and net income.

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 $4 million in increased cash flow.

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. The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010. For 2008 and 2009, a 6% deduction was available to the Company. Thereafter, the allowed rate is 9%; however, due to increased tax deductions from bonus depreciation there was no domestic production deduction available for 2010 and none is projected to be available for 2011.

Construction Projects

Cleveland County Units 1-4

In December 2008, the Company announced that it will build an electric generating plant in Cleveland County, North Carolina. The plant will consist of four combustion turbine natural gas generating units with a total generating capacity of 720 MWs. The units are expected to begin commercial operation in 2012. Costs incurred through December 31, 2010 were $175.8 million. The total estimated construction cost is expected to be between $350 million and $400 million, and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Nacogdoches Biomass Plant

In October 2009, the Company acquired all of the outstanding membership interests of Nacogdoches Power LLC (Nacogdoches) from American Renewables LLC, the original developer of the project. Nacogdoches is constructing a biomass generating plant in Sacul, Texas with an estimated capacity of 100 MWs. The generating plant will be fueled from wood waste. Construction commenced in 2009 and the plant is expected to begin commercial operation in 2012. Costs incurred through December 31, 2010 were $249.8 million. The total estimated cost of the project is expected to be between $475 million and $500 million, and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Other Matters

From time to time, 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. Litigation over environmental issues and claims of various types, including property and other 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 consolidated 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.

Revenue Recognition

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with GAAP. In general, the Company's power sale transactions can be classified in one of four categories: leases, non-derivatives or normal sale derivatives, cash flow hedges, and mark-to-market transactions. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 9 to the financial statements. The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract.

Lease Transactions

The Company considers the following factors to determine whether the sales contract is a lease:

- Assessing whether specific property is explicitly or implicitly identified in the agreement;
- Determining whether the fulfillment of the arrangement is dependent on the use of the identified property; and
- Assessing whether the arrangement conveys to the purchaser the right to use the identified property.

If the contract meets the above criteria for a lease, the Company performs further analysis as to whether the lease is classified as operating or capital. As none of the transactions transfer title of the underlying property to the counterparty, all of Company's power sales contracts classified as leases are accounted for as operating leases.

Non-Derivative and Normal Sale Derivative Transactions

If the sales contract is not considered a lease, the Company further considers the following factors to determine proper transaction classification:

- Assessing whether a sales contract meets the definition of a derivative;
- Assessing whether a sales contract meets the definition of a capacity contract;
- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery; and
- Ensuring that the contract quantities do not exceed available generating capacity (including purchased capacity).

Contracts that do not meet the definition of a derivative or are designated as normal sales (i.e. capacity contracts which provide for the sale of electricity that involve physical delivery in quantities within the Company's available generating capacity) are exempt from fair value accounting in accordance with GAAP. As a result, such transactions are accounted for as executory contracts. The related revenue is recognized on an accrual basis in amounts equal to the lesser of the cumulative levelized amount or the cumulative amount billable under the contract over the respective contract periods. Revenues are recorded on a gross or net basis in accordance with GAAP. Contracts recorded on the accrual basis represented the majority of the Company's operating revenues for the years ended December 31, 2010, 2009, and 2008.

Cash Flow Hedge Transactions

The Company further considers the following in designating other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions:

- Identifying the hedging instrument, the hedged transaction, and the nature of the risk being hedged; and
- Assessing hedge effectiveness at inception and throughout the contract term.

These contracts are marked to market through other comprehensive income over the life of the contract. Realized gains and losses are then recognized in revenues as incurred.

Mark-to-Market Transactions

Contracts for sales and purchases of electricity, which meet the definition of a derivative and that either do not qualify or are not designated as normal sales or as cash flow hedges, are marked-to-market and recorded directly through net income.

Impairment of Long Lived Assets and Intangibles

The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company's intangible assets consist of acquired PPAs that are amortized over the term of the PPAs and goodwill resulting from acquisitions. The Company evaluates the carrying value of these assets in accordance with accounting standards whenever indicators of potential impairment exist, or annually in the case of goodwill. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses or a projection of continuing losses, a significant decrease in market prices, and the inability to remarket generating capacity for an extended period. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:

- Future demand for electricity based on projections of economic growth and estimates of available generating capacity;
- Future power and natural gas prices, which have been quite volatile in recent years; and
- Future operating costs.

Acquisition Accounting

The Company has been engaged in a strategy of acquiring assets. The Company has accounted for these acquisitions under the purchase method in accordance with GAAP. Accordingly, the Company has included these operations in the consolidated financial statements from the respective date of acquisition. The purchase price of each acquisition was allocated to the fair value of the identifiable assets and liabilities. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions after December 31, 2008 have been expensed as incurred.

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, 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 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.

Depreciation

Depreciation of the original cost of assets is computed under the straight-line method and applies a composite depreciation rate based on the assets' estimated useful lives determined by management. The primary assets in property, plant, and equipment are power plants, all of which have an estimated composite life ranging from 24 to 35 years. These lives reflect a weighted average of the significant components (retirement units) that make up the plants. Key judgments impacting the estimated lives of component parts include estimates of run-hours and starts which can impact the future utility of these components. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.

When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

Convertible Investment Tax Credits

Under the ARRA, certain costs related to the Nacogdoches plant construction are eligible for ITCs or cash grants. The Company has elected to receive ITCs. A high degree of judgment is required in determining which construction expenditures qualify for ITCs. See Note 1 to the financial statements under "Convertible Income Tax Credits" for additional information.

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 as needed to meet its future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $327.1 million in 2010, compared to $318.1 million in 2009. This increase was mainly due to an increase in convertible ITCs. Net cash used for investing activities totaled $306.6 million in 2010, compared to $364.1 million in 2009. This decrease was primarily due to the Nacogdoches and West Georgia acquisitions in October 2009 and December 2009, respectively, partially offset by an increase in construction work in progress related to construction activities at Cleveland County and Nacogdoches. Net cash used for financing activities totaled $15.5 million in 2010, compared to $15.2 million of cash provided from financing activities in 2009. The increase in cash used is mainly due to a smaller increase in short-term borrowings in 2010 as compared to prior years.

Net cash provided from operating activities totaled $318.1 million in 2009, increasing 20.4% from 2008. This increase was primarily due to a reduction in costs incurred on the OUC construction contract, receipt of convertible ITCs, and timing of tax payments. Net cash used for investing activities totaled $364.1 million in 2009, increasing 324.5% from 2008. This increase was primarily due to the Nacogdoches and West Georgia acquisitions. Gross property additions to utility plant of $137.1 million in 2009 were primarily related to the construction of the Cleveland County and Nacogdoches facilities. Net cash provided from financing activities was $15.2 million in 2009, compared to $140.6 million used in 2008. This change was primarily due to the issuance of short-term debt in 2009.

Net cash provided from operating activities totaled $264.3 million in 2008, decreasing 16.2% from 2007. This decrease was primarily due to cash outflows for engineering, procurement, and construction services to build a combined cycle unit for the OUC. Net cash used for investing activities totaled $85.8 million in 2008, decreasing 53.4% from 2007. This decrease was primarily due to the completion of Plant Oleander Unit 5 in 2007 and the completion of Plant Franklin Unit 3 in 2008. Gross property additions to utility plant of $50.0 million in 2008 were primarily related to the completion of Plant Franklin Unit 3. Net cash used for financing activities was $140.6 million in 2008, decreasing 12.9% from 2007. This decrease was primarily due to reduced levels of short-term debt in 2008.

Significant asset changes in the balance sheet during 2010 include an increase in construction work in progress related to Cleveland County and Nacogdoches construction activities.

Significant asset changes in the balance sheet during 2009 include increases related to the West Georgia and Nacogdoches acquisitions. Construction work in progress increased due to Cleveland County and Nacogdoches construction activities. Prepaid long-term service agreements increased due to the timing of outage activities. Additionally, prepaid income taxes decreased due to the timing of income tax payments. Cash decreased due to the West Georgia and Nacogdoches acquisitions and increased construction activity.

Significant liability and stockholder's equity changes in the balance sheet during 2010 include an increase in notes payable mainly related to Cleveland County and Nacogdoches construction activities and an increase in accumulated deferred income taxes primarily due to bonus depreciation.

Significant liability and stockholder's equity changes in the balance sheet during 2009 include the issuance of $118.9 million in notes payable, an increase in accounts payable related to construction projects, and a decrease in net billings in excess of cost due to the timing of scheduled payments and costs incurred with regard to the OUC construction contract. In 2009, the Company also paid $106.1 million in dividends to Southern Company.

Sources of Capital

The Company may use operating cash flows, external funds, or equity capital or loans from Southern Company to finance any new projects, acquisitions, and ongoing capital requirements. The Company expects to generate external funds from the issuance of unsecured senior debt and commercial paper or utilization of credit arrangements from banks. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

The Company's current liabilities frequently exceed current assets due to the use of short-term indebtedness as a funding source, as well as cash needs which can fluctuate significantly due to the seasonality of the business. To meet liquidity and capital resource requirements, at December 31, 2010, the Company had $400 million of committed credit arrangements with banks that expire in 2012. There were no borrowings under this facility outstanding at December 31, 2010. Proceeds from these credit arrangements may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. During 2010, the Company had an average of $169 million of commercial paper outstanding at a weighted average interest rate of 0.4% per annum and the maximum amount outstanding was $259 million. At December 31, 2010, the Company had $204 million of commercial paper outstanding. During 2009, the Company had an average of $7 million of commercial paper outstanding at a weighted average interest rate of 0.4% per annum. At December 31, 2009, the Company had $119 million of commercial paper outstanding. The maximum amount outstanding during 2009 was $119 million. Management believes that the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, and cash. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Financing Activities

In 2010 and 2009, the Company did not issue or redeem any long-term debt securities.

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 Baa2, or 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 Baa2 rating were approximately $9 million and at a BBB- and/or Baa3 rating were approximately $360 million. At December 31, 2010, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $1.0 billion. 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.

In addition, through the acquisition of Plant Rowan, the Company assumed PPAs with Duke Energy and NCMPA1 that could require collateral, but not accelerated payment, in the event of a downgrade of the Company's credit. The Duke Energy PPA defines the downgrade to be below BBB- or Baa3. The NCMPA1 PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade for both PPAs.

Market Price Risk

The Company is exposed to market risks, including changes in interest rates, certain energy-related commodity prices, and, occasionally, currency exchange rates. To manage the volatility attributable to these exposures, the Company takes 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 tests, and sensitivity analysis.

At December 31, 2010, the Company had no variable long-term debt outstanding. Therefore, there would be no effect on annualized interest expense related to long-term debt if the Company sustained a 100 basis point change in interest rates. Since a significant portion of outstanding indebtedness bears interest at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot be determined at this time.

Because energy from the Company's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, the Company's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

The changes in fair value of energy-related derivative contracts for the years ended December 31 were as follows:

	2010 Changes	2009 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (3.5)**	$ 3.4
Contracts realized or settled	**1.5**	(2.0)
Current period changes[(a)]	**(1.5)**	(4.9)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (3.5)**	$ (3.5)

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

For the year ended December 31, 2010, there was no change in the total fair value of the energy-related derivative contracts. For the year ended December 31, 2009, there was a $6.9 million decrease in the fair value positions of the energy-related derivative contracts, which is due to both volume and price changes in power and natural gas positions.

The net hedge positions at December 31, 2010 and December 31, 2009 and respective period end dates that support these changes were as follows:

	December 31, 2010	December 31, 2009
Power (net sold)		
Megawatt hours (MWH) (in millions)	**0.9**	2.7
Weighted average contract cost per MWH above (below) market prices (in dollars)	**$(2.33)**	$ (0.36)
Natural gas (net purchase)		
Commodity – million British thermal unit (mmBtu)	**13.0**	8.3
Location basis – million mmBtu	**-**	2.0
Commodity – weighted average contract cost per mmBtu above (below) market prices (in dollars)	**$0.11**	$ 0.29
Location basis – weighted average contract cost per mmBtu above (below) market prices (in dollars)	**$-**	$ (0.04)

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets (liabilities) as follows:

Asset (Liability) Derivatives	**2010**	2009
	(in millions)	
Cash flow hedges	**$ (1.0)**	$ (2.5)
Not designated	**(2.5)**	(1.0)
Total fair value	**$ (3.5)**	$ (3.5)

Gains and losses on energy-related derivatives used by the Company to hedge anticipated purchases and sales are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Total net unrealized pre-tax gains (losses) recognized in the statements of income for the years ended December 31, 2010, 2009, and 2008 for energy-related derivative contracts that are not hedges were $(1.5) million, $(5.2) million, and $0.9 million, respectively.

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 8 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2010 were as follows:

	December 31, 2010 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ -	$ -	$ -	$ -
Level 2	(3.5)	(3.6)	(0.3)	0.4
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(3.5)	$ (3.6)	$ (0.3)	$ 0.4

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related derivative contracts. The Company only enters into agreements with counterparties that have investment grade credit ratings by S&P and Moody's 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. See Note 1 to the financial statements under "Financial Instruments" and Note 9 to the financial statements for additional information.

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 capital program of the Company is currently estimated to be $540 million for 2011, $144 million for 2012, and $37 million for 2013. These amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements. Planned expenditures for plant acquisitions may vary due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. The Company is currently constructing a four-unit combustion turbine generating plant in Cleveland County, North Carolina and a biomass generating facility in Sacul, Texas. See FUTURE EARNINGS POTENTIAL – "Construction Projects" herein for additional information.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 6, 7, and 9 to the financial statements for additional information.

Contractual Obligations

	2011	2012-2013	2014-2015	After 2015	Uncertain Timing [c]	Total
			(in millions)			
Long-term debt[a] –						
Principal	$ -	$ 575.0	$ 525.0	$ 200.0	$ -	$1,300.0
Interest	74.3	112.6	76.7	267.7	-	531.3
Energy-related derivative obligations[b]	5.8	0.4	-	-	-	6.2
Operating leases	0.5	1.0	0.9	22.3	-	24.7
Unrecognized tax benefits and interest[c]	-	-	-	-	2.3	2.3
Purchase commitments[d] –						
Capital[e]	539.6	181.2	-	-	-	720.8
Natural gas[f]	338.2	485.9	295.2	229.2	-	1,348.5
Biomass fuel[g]	-	32.0	36.0	110.0	-	178.0
Purchased power[h]	7.8	99.6	105.1	241.7	-	454.2
Long-term service agreements[i]	48.8	86.6	101.0	878.3	-	1,114.7
Total	$1,015.0	$1,574.3	$1,139.9	$1,949.2	$ 2.3	$5,680.7

(a) All amounts are reflected based on final maturity dates. The Company plans to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

(b) For additional information, see Notes 1 and 9 to the financial statements.

(c) The timing related to the realization of $2.3 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.

(d) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $147.4 million, $136.7 million, and $147.7 million, respectively.

(e) The Company provides forecasted capital expenditures for a three-year period. Amounts represent estimates for potential plant acquisitions and new construction as well as ongoing capital improvements.

(f) 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.

(g) Biomass fuel commitments are based on minimum committed tonnage of wood waste purchases for Plant Nacogdoches. Plant Nacogdoches is expected to begin commercial operation in 2012. Amounts reflected include price escalation based on inflation indices.

(h) Purchased power commitments of $71.5 million in 2012-2013, $74.4 million in 2014-2015, and $241.7 million after 2015 will be resold under a third party agreement to EnergyUnited. The purchases will be resold at cost.

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

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 environmental regulations and expenditures, financing activities, impacts of the 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, impacts of revisions to depreciation estimates, start and completion of construction projects, filings with federal regulatory authorities, impacts of adoption of new accounting rules, plans and estimated costs for new generation resources, 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 and emissions of sulfur, mercury, carbon, soot, particulate matter, hazardous air pollutants, and other substances, financial reform legislation, and 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;
- 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;
- advances in technology;
- state and federal rate regulations;
- the ability to control costs and avoid cost overruns during the development and construction of facilities;
- 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 Securities and Exchange Commission.

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

[This page intentionally left blank]

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2010, 2009, and 2008
Southern Power Company and Subsidiary Companies 2010 Annual Report

	2010	2009	2008
		(in thousands)	
Operating Revenues:			
Wholesale revenues, non-affiliates	**$751,575**	$394,366	$667,979
Wholesale revenues, affiliates	**370,630**	544,415	638,266
Other revenues	**6,940**	7,870	7,296
Total operating revenues	**1,129,145**	946,651	1,313,541
Operating Expenses:			
Fuel	**391,535**	232,466	424,800
Purchased power, non-affiliates	**72,653**	79,355	132,222
Purchased power, affiliates	**97,408**	64,587	195,743
Other operations and maintenance	**147,433**	136,655	147,711
Loss (gain) on sale of property	**478**	4,977	(6,015)
Depreciation and amortization	**119,026**	98,135	88,511
Taxes other than income taxes	**17,818**	16,920	17,700
Total operating expenses	**846,351**	633,095	1,000,672
Operating Income	**282,794**	313,556	312,869
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(76,111)**	(84,963)	(83,212)
Profit recognized on construction contract	**470**	13,296	-
Other income (expense), net	**(372)**	(374)	7,594
Total other income and (expense)	**(76,013)**	(72,041)	(75,618)
Earnings Before Income Taxes	**206,781**	241,515	237,251
Income taxes	**76,759**	85,663	92,892
Net Income	**$130,022**	$155,852	$144,359

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2010, 2009, and 2008
Southern Power Company and Subsidiary Companies 2010 Annual Report

	2010	2009	2008
		(in thousands)	
Operating Activities:			
Net income	**$130,022**	$155,852	$144,359
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**132,802**	110,427	102,783
Deferred income taxes	**33,981**	22,950	70,338
Convertible investment tax credits received	**26,400**	16,800	-
Deferred revenues	**(5,586)**	2,288	(703)
Mark-to-market adjustments	**1,492**	5,204	(925)
Accumulated billings on construction contract	**401**	48,451	85,619
Accumulated costs on construction contract	**(65)**	(46,765)	(110,096)
Profit recognized on construction contract	**(470)**	(13,296)	-
Loss (gain) on sale of property	**505**	4,977	(6,015)
Other, net	**5,708**	5,630	4,851
Changes in certain current assets and liabilities --			
-Receivables	**(22,674)**	(9,717)	(11,156)
-Fossil fuel stock	**2,604**	2,738	(2,640)
-Materials and supplies	**443**	(5,345)	2,773
-Prepaid income taxes	**4,784**	16,296	(21,338)
-Other current assets	**(167)**	(298)	1,413
-Accounts payable	**655**	2,043	10,451
-Accrued taxes	**15,928**	88	(1,622)
-Accrued interest	**53**	7	(252)
-Other current liabilities	**305**	(199)	(3,575)
Net cash provided from operating activities	**327,121**	318,131	264,265
Investing Activities:			
Property additions	**(299,602)**	(137,133)	(49,964)
Cash paid for acquisitions	**-**	(194,156)	-
Sale of property	**4,000**	84	5,073
Change in construction payables, net	**31,290**	13,435	(7,529)
Payments pursuant to long-term service agreements	**(41,598)**	(46,120)	(31,725)
Other investing activities	**(721)**	(184)	(1,625)
Net cash used for investing activities	**(306,631)**	(364,074)	(85,770)
Financing Activities:			
Increase (decrease) in notes payable, net	**84,956**	118,948	(49,748)
Proceeds - capital contributions	**6,659**	2,353	3,642
Payment of common stock dividends	**(107,100)**	(106,100)	(94,500)
Net cash provided from (used for) financing activities	**(15,485)**	15,201	(140,606)
Net Change in Cash and Cash Equivalents	**5,005**	(30,742)	37,889
Cash and Cash Equivalents at Beginning of Year	**7,152**	37,894	5
Cash and Cash Equivalents at End of Year	**$12,157**	$ 7,152	$ 37,894
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $12,110, $1,624 and $7,075 capitalized, respectively)	**$63,229**	$ 73,064	$ 69,716
Income taxes (net of refunds and investment tax credits)	**(6,246)**	30,220	47,611
Noncash value of business exchanged in West Georgia acquisition	**-**	70,839	-
Noncash transactions - accrued property additions at year-end	**46,764**	15,474	2,039

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

CONSOLIDATED BALANCE SHEETS

At December 31, 2010 and 2009

Southern Power Company and Subsidiary Companies 2010 Annual Report

Assets	2010	2009
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$12,157**	$ 7,152
Receivables --		
Customer accounts receivable	**76,508**	28,873
Other accounts receivable	**1,979**	2,064
Affiliated companies	**19,673**	38,561
Fossil fuel stock, at average cost	**13,663**	15,351
Materials and supplies, at average cost	**33,934**	31,607
Prepaid service agreements - current	**41,627**	44,090
Prepaid income taxes	**652**	5,177
Other prepaid expenses	**3,343**	3,176
Assets from risk management activities	**2,160**	4,901
Other current assets	**20**	6,754
Total current assets	**205,716**	187,706
Property, Plant, and Equipment:		
In service	**3,038,877**	2,994,463
Less accumulated provision for depreciation	**535,800**	439,457
Plant in service, net of depreciation	**2,503,077**	2,555,006
Construction work in progress	**427,788**	153,982
Total property, plant, and equipment	**2,930,865**	2,708,988
Other Property and Investments:		
Goodwill	**1,839**	1,794
Other intangible assets, net of amortization of $693 and $17 at December 31, 2010 and December 31, 2009, respectively	**48,426**	49,102
Total other property and investments	**50,265**	50,896
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	**69,690**	74,513
Other deferred charges and assets -- affiliated	**3,275**	3,540
Other deferred charges and assets -- non-affiliated	**16,540**	17,410
Total deferred charges and other assets	**89,505**	95,463
Total Assets	**$3,276,351**	$3,043,053

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

CONSOLIDATED BALANCE SHEETS

At December 31, 2010 and 2009

Southern Power Company and Subsidiary Companies 2010 Annual Report

Liabilities and Stockholder's Equity	**2010**	2009
	(in thousands)	
Current Liabilities:		
Notes payable	**$ 203,904**	$ 118,948
Accounts payable --		
Affiliated	**69,656**	58,493
Other	**45,248**	31,128
Accrued taxes --		
Accrued income taxes	**5,562**	1,449
Other accrued taxes	**2,775**	2,576
Accrued interest	**29,976**	29,923
Liabilities from risk management activities	**5,773**	8,119
Billings in excess of cost on construction contract	**-**	297
Other current liabilities	**305**	26
Total current liabilities	**363,199**	250,959
Long-Term Debt:		
Senior notes --		
6.25% due 2012	**575,000**	575,000
4.875% due 2015	**525,000**	525,000
6.375% due 2036	**200,000**	200,000
Unamortized debt discount	**(2,140)**	(2,393)
Long-term debt	**1,297,860**	1,297,607
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**277,440**	238,293
Deferred convertible investment tax credits	**54,395**	16,800
Deferred capacity revenues -- affiliated	**30,533**	36,369
Other deferred credits and liabilities -- affiliated	**4,635**	5,651
Other deferred credits and liabilities -- non-affiliated	**16,204**	2,252
Total deferred credits and other liabilities	**383,207**	299,365
Total Liabilities	**2,044,266**	1,847,931
Common Stockholder's Equity:		
Common stock, par value $0.01 per share --		
Authorized - 1,000,000 shares		
Outstanding - 1,000 shares	**-**	-
Paid-in capital	**871,121**	864,462
Retained earnings	**374,983**	352,061
Accumulated other comprehensive income (loss)	**(14,019)**	(21,401)
Total common stockholder's equity	**1,232,085**	1,195,122
Total Liabilities and Stockholder's Equity	**$3,276,351**	$3,043,053
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

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

Southern Power Company and Subsidiary Companies 2010 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2007	1	$-	$858,466	$253,131	$(33,710)	$1,077,887
Net income	-	-	-	144,359	-	144,359
Capital contributions from parent company	-	-	3,643	-	-	3,643
Other comprehensive income (loss)	-	-	-	-	7,653	7,653
Cash dividends on common stock	-	-	-	(94,500)	-	(94,500)
Other	-	-	-	(681)	-	(681)
Balance at December 31, 2008	1	-	862,109	302,309	(26,057)	1,138,361
Net income	-	-	-	155,852	-	155,852
Capital contributions from parent company	-	-	2,353	-	-	2,353
Other comprehensive income (loss)	-	-	-	-	4,656	4,656
Cash dividends on common stock	-	-	-	(106,100)	-	(106,100)
Balance at December 31, 2009	**1**	**-**	**864,462**	**352,061**	**(21,401)**	**1,195,122**
Net income	**-**	**-**	**-**	**130,022**	**-**	**130,022**
Capital contributions from parent company	**-**	**-**	**6,659**	**-**	**-**	**6,659**
Other comprehensive income (loss)	**-**	**-**	**-**	**-**	**7,382**	**7,382**
Cash dividends on common stock	**-**	**-**	**-**	**(107,100)**	**-**	**(107,100)**
Balance at December 31, 2010	**1**	**$-**	**$871,121**	**$374,983**	**$(14,019)**	**$1,232,085**

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

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

Southern Power Company and Subsidiary Companies 2010 Annual Report

	2010	2009	2008
		(in thousands)	
Net income	**$130,022**	$155,852	$144,359
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $591, $(664), and $351, respectively	**938**	(1,044)	529
Reclassification adjustment for amounts included in net income, net of tax of $3,894, $3,875, and $4,554, respectively	**6,444**	5,700	7,124
Total other comprehensive income (loss)	**7,382**	4,656	7,653
Comprehensive Income	**$137,404**	$160,508	$152,012

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is also the parent company of four traditional operating companies, 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 – Alabama Power Company (APC), Georgia Power Company (GPC), Gulf Power Company (Gulf Power), and Mississippi Power Company (MPC) – are vertically integrated utilities providing electric service in four Southeastern states. The Company 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 Company is subject to regulation by the Federal Energy Regulatory Commission (FERC). The Company follows generally accepted accounting principles (GAAP). The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

The financial statements include the accounts of the Company and its wholly-owned subsidiaries, Southern Company – Florida LLC, Oleander Power Project, LP (Oleander), Southern Power Company – Orlando Gasification LLC (SPC-OG), and Nacogdoches Power LLC, which own, operate, and maintain the Company's ownership interests in Plant Stanton Unit A and Plant Oleander, constructed the combined cycle for the Orlando Utilities Commission (OUC), and is constructing a biomass generating facility, respectively. All intercompany accounts and transactions have been eliminated in consolidation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at amounts in compliance with FERC regulation: general and design engineering, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, labor, and other services with respect to business and operations and Southern Company system fleet of generating units (power pool) transactions. Because the Company has no employees, all employee-related charges are rendered at amounts in compliance with FERC regulation under agreements with SCS. Costs for these services from SCS amounted to approximately $103.4 million in 2010, $133.0 million in 2009, and $207.4 million in 2008. Approximately $89.2 million in 2010, $83.1 million in 2009, and $87.9 million in 2008 were operations and maintenance expenses; the remainder was recorded to construction work in progress, other assets, and billings in excess of cost on construction contract. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission 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.

Total billings for all power purchase agreements (PPAs) in effect with affiliates totaled $230.8 million, $485.1 million, and $539.6 million in 2010, 2009, and 2008, respectively. Included in these billings were $30.5 million and $36.4 million of "Deferred capacity revenues – affiliated" recorded on the balance sheets at December 31, 2010 and 2009, respectively. The Company and the traditional operating companies may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements.

The Company and the traditional operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

In January 2010, the Company sold turbine rotor assembly parts to Gulf Power for $6 million. In September 2010, the Company purchased turbine rotor assembly parts owned by GPC, Gulf Power, and MPC for approximately $4 million, $1 million, and $7 million, respectively. These affiliate transactions were made in accordance with FERC and state Public Service Commission (PSC) rules and guidelines.

In 2009, there were no material transactions involving the sale of property to affiliated companies.

In 2008, Gulf Power and APC sold turbine rotor assemblies to the Company for $9.4 million and $6.3 million, respectively. Additionally, the Company sold a turbine rotor assembly to APC for $8.2 million and sold a compressor assembly to GPC for $3.9 million. No gain or loss was recognized in the Company's consolidated statements of income. These affiliate transactions were made in accordance with FERC and state PSC rules and guidelines.

Acquisition Accounting

The Company has been engaged in a strategy of acquiring assets. The Company has accounted for these acquisitions under the purchase method in accordance with GAAP. Accordingly, the Company has included these operations in the consolidated financial statements from the respective date of acquisition. The purchase price of each acquisition was allocated to the fair value of the identifiable assets and liabilities. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions have been expensed as incurred.

Revenues

The Company sells capacity at rates specified under contractual terms for long-term PPAs. These PPAs are generally accounted for as operating leases, non-derivatives, or normal sale derivatives. Revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Revenues from PPAs classified as non-derivatives or normal sales are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods.

The Company may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains (losses) on such contracts are recorded in wholesale revenues. See Note 9 to the financial statements for further information.

Energy is generally sold at market-based rates and the associated revenue is recognized as the energy is delivered. Transmission revenues and other fees are recognized as incurred as other operating revenues. Revenues are recorded on a gross basis for all full requirements PPAs. See "Financial Instruments" herein for additional information.

Significant portions of the Company's revenues have been derived from certain customers pursuant to PPAs. For the year ended December 31, 2010, GPC accounted for 17.7% of total revenues, Florida Power & Light accounted for 11.4%, and Progress Energy Carolina accounted for 8.2% of total revenues. For the year ended December 31, 2009, GPC accounted for 43.7% of total revenues, APC accounted for 6.6% of total revenues, and Sawnee Electric Membership Corporation accounted for 6.0% of total revenues. For the year ended December 31, 2008, GPC accounted for 36.5% of total revenues, Sawnee Electric Membership Corporation accounted for 6.1% of total revenues, and Flint Electric Membership Corporation accounted for 5.3% of total revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel costs also include emissions allowances which are expensed as the emissions occur.

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. 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.

Convertible Investment Tax Credits

Under the American Recovery and Reinvestment Act of 2009, certain costs related to the Nacogdoches plant construction are eligible for investment tax credits (ITCs) or cash grants. The Company has elected to receive ITCs. The credits are recorded as a deferred credit, which will be amortized to income tax expense over the life of the asset, and the tax basis of the asset is reduced by 50% of the credits received, resulting in a deferred tax asset. The Company has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense as costs are incurred during the construction period. This basis difference will reverse and be recorded to income tax expense over the useful life of the asset once placed in service. The credits received during the year are shown within operating activities in the consolidated statements of cash flows.

Property, Plant, and Equipment

The Company's depreciable property, plant, and equipment consists entirely of generation assets.

Property, plant, and equipment is stated at original cost. Original cost includes: materials, direct labor incurred by contractors and affiliated companies, minor items of property, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred.

Depreciation

Depreciation of the original cost of assets is computed under the straight-line method and applies a composite depreciation rate based on the assets' estimated useful lives determined by the Company. The primary assets in property, plant, and equipment are power plants, all of which have an estimated composite depreciable life ranging from 24-35 years. These lives reflect a composite of the significant components (retirement units) that make up the plants. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.

When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized.

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.

At December 31, 2010, the Company had no material liability for asset retirement obligations.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets and intangibles for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company's intangible assets consist of acquired PPAs that are amortized over the term of the PPA and goodwill resulting from acquisitions. The average term of these PPAs is 20 years. The determination of whether an impairment has occurred is based on 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 estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. Impairment of goodwill is assessed on an annual basis. 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.

The amortization expense for the PPAs is as follows:

	Amortization Expense
	(in millions)
2010	$ 0.7
2011	0.8
2012	1.8
2013	2.4
2014	2.4
2015 and beyond	41.0
Total	$ 49.1

Deferred Project Development Costs

The Company capitalizes project development costs once it is determined that it is probable that a specific site will be acquired and a power plant constructed. These costs include professional services, permits, and other costs directly related to the construction of a new project. These costs are generally transferred to construction work in progress upon commencement of construction. The total deferred project development costs were $9.6 million at December 31, 2010, $9.0 million at December 31, 2009, and $8.9 million at December 31, 2008.

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 costs of 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 cost of oil, natural gas, and emissions allowances. The Company maintains minimal oil levels for use at Plant Dahlberg, Plant Oleander, Plant Rowan, and Plant West Georgia. The Company has contracts in place for natural gas storage. These contracts help to ensure normal operations of the Company's natural gas generating units. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used.

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 8 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions. This results in the deferral of related gains and losses in other comprehensive income (OCI) 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 in the financial statement line item where they will eventually settle. See Note 9 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 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.

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2). See Note 8 for all other items recognized at fair value in the financial statements.

Other Income and (Expense)

Other income and (expense) includes non-operating revenues and expenses. Revenues are recognized when earned and expenses are recognized when incurred.

The Company had a long-term contract for engineering, procurement, and construction services to build a combined cycle unit for the OUC. Construction activities commenced in 2006 and were substantially completed in 2009. Billings and costs are recognized using the percentage of completion method. The Company utilizes the cost-to-cost approach as this method is less subjective than relying on assessments of physical progress. The percentage of completion represents the percentage of the total costs incurred to the estimated total cost of the contract. Billings and costs are recognized on a net basis by applying this percentage to the total revenues and estimated costs of the contract and are recorded in other income and (expense) in the consolidated statements of income. Net profit recognized under the long-term construction contract for the OUC was $0.5 million in 2010 and $13.3 million in 2009. No profit or loss was recognized in 2008.

In 2008, the Company received a fee of $6.4 million for participating in an asset auction. The Company was not the successful bidder in the asset auction.

Interest related to the construction of new facilities is capitalized in accordance with GAAP.

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 of amounts included in net income.

Variable Interest Entities

Effective January 1, 2010, Southern Power adopted new accounting guidance which modified the consolidation model and expanded disclosures related to variable interest entities (VIE). The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

Southern Power has certain wholly-owned subsidiaries that are determined to be VIEs. Southern Power is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests. The adoption of this new accounting guidance did not result in the Company consolidating any VIEs that were not already consolidated under previous guidance, nor deconsolidating any VIEs.

2. ACQUISITIONS AND DIVESTITURES

Nacogdoches Power LLC Acquisition

In October 2009, the Company acquired all of the outstanding membership interests of Nacogdoches Power LLC (Nacogdoches) from American Renewables LLC, the original developer of the project. Nacogdoches is constructing a biomass generating plant in Sacul, Texas with an estimated capacity of 100 megawatts (MWs). The generating plant will be fueled from wood waste. Construction commenced in late 2009 and the plant is expected to begin commercial operation in 2012. The total estimated cost of the project is expected to be between $475 million and $500 million. The output of the plant is contracted under a PPA with Austin Energy that begins in 2012 and expires in 2032 or until a contractual limit of $2.3 billion is reached. This PPA will be accounted for as an operating lease.

The Company's acquisition of the interests in Nacogdoches included cash consideration of approximately $50.1 million. The Nacogdoches acquisition is in accordance with the Company's overall growth strategy. There are no contingent consideration arrangements and no significant assets or liabilities arising from contingencies. No goodwill was recorded as a result of this acquisition. An intangible asset related to the assumed PPA with Austin Energy was recognized. Due diligence and transition costs for Nacogdoches were expensed as incurred and were not material. The fair value of the consideration transferred and the fair value of each major class of assets and liabilities at the acquisition date was as follows:

As of October 2009	
	(in millions)
Construction work in progress	$16.2
Other assets	0.1
Intangible assets	33.8
Total fair value of the membership interests in Nacogdoches	$50.1

West Georgia Generating Company, LLC Acquisition

In December 2009, the Company acquired all of the outstanding membership interests of West Georgia Generating Company, LLC (West Georgia) from Broadway Gen Funding, LLC (Broadway), an affiliate of LS Power. West Georgia was merged into the Company and the Company now owns a 669-MW nameplate capacity generating facility consisting of four combustion turbine natural gas generating units with oil back-up. The output from two units is contracted under PPAs with the Municipal Electric Authority of Georgia (MEAG Power) and the Georgia Energy Cooperative, Inc. (GEC). The MEAG Power agreement began in 2009 and expires in 2029. The GEC agreement began in 2010 and expires in 2030.

The Company's acquisition of the interests in West Georgia was pursuant to an agreement which included the transfer of all the outstanding membership interests of DeSoto County Generating Company LLC (DeSoto) from the Company to Broadway and the payment by the Company of $144.0 million in cash consideration. The carrying values of the major classes of assets disposed of were $2.0 million in fossil fuel stock, $1.2 million in materials and supplies, $72.1 million in property, plant, and equipment, and $0.8 million in other deferred assets. The transaction was treated as a like-kind exchange for income tax purposes. The West Georgia acquisition is in accordance with the Company's overall growth strategy. There are no contingent consideration arrangements and no significant assets or liabilities arising from contingencies. The goodwill arising from the acquisition consists largely of synergies and economies of scale from combining the operations of the Company and West Georgia and is expected to be tax deductible. Due diligence and transition costs for West Georgia were expensed as incurred and were not material.

The final fair value of the consideration transferred and the fair value of each major class of assets and liabilities at the acquisition date was as follows:

As of December 2009	
	(in millions)
Customer accounts receivable	$ 0.4
Fossil fuel stock	1.8
Materials and supplies	0.9
Property, plant, and equipment	192.4
Other assets	2.5
Goodwill	1.8
Intangible assets (PPAs)	15.3
Accounts payable	(0.3)
Total fair value of the membership interests in West Georgia	214.8
Fair value of DeSoto interests	(70.8)
Cash consideration transferred	$ 144.0

Revenues and expenses recognized by the Company for West Georgia operations after the closing date were not material. PPA amortization expense for 2009 was not material.

Pro Forma Information

The following unaudited pro forma financial information gives effect to the Nacogdoches acquisition, the West Georgia acquisition, and the DeSoto divestiture as if they had occurred as of the beginning of the periods presented. The pro forma financial information is not intended to represent or be indicative of the consolidated results of operations or financial condition of the Company that would have been reported had the acquisitions and divestiture been completed as of the dates presented nor should the information be taken as representative of any future consolidated results of operations or financial condition of the Company.

For the Twelve Months Ended December 31	2009	2008
	(in millions)	
Pro forma revenues	$ 957.4	$1,353.3
Pro forma net income	151.1	146.6

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. Litigation over environmental issues and claims of various types, including property and other 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 and its subsidiaries 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.

FERC Matters

The majority of the Company's generation fleet is operated under the Intercompany Interchange Contract (IIC), as approved by the FERC. In May 2005, the FERC initiated a proceeding to examine certain aspects of the IIC, the operation of the power pool, and the Company's compliance with various regulatory requirements. In 2006, the proceeding was resolved pursuant to the terms of an order on settlement issued by the FERC. In 2007, the FERC approved, with certain modifications, a compliance plan submitted by Southern Company in connection with the settlement order. In 2008, the FERC division of audits issued its final audit report pertaining to compliance implementation and related matters. On December 29, 2010, the FERC accepted the audit report finding the Company to be in full compliance with the terms of the settlement order and terminated the proceeding. This matter is now concluded.

Income Tax Matters

The Company submitted a change in the tax accounting method for repair costs associated with the Company's generation assets 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 $6 million for the Company. Although Internal Revenue Service (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. The ultimate outcome of this matter cannot be determined at this time.

Carbon Dioxide Litigation

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 that 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 a similar case. 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 Kivalina case, 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.

4. JOINT OWNERSHIP AGREEMENTS

The Company is a 65% owner of Plant Stanton A, a combined-cycle project with a nameplate capacity of 630 MWs. The unit is co-owned by the OUC (28%), Florida Municipal Power Agency (3.5%), and Kissimmee Utility Authority (3.5%). The Company has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton A. As of December 31, 2010, $155.9 million was recorded in plant in service with associated accumulated depreciation of $24.8 million. These amounts represent the Company's share of the total plant assets and each owner is responsible for providing its own financing. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

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

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2010	2009	2008
		(in millions)	
Federal –			
Current	**$ 36.1**	$ 55.0	$ 18.9
Deferred	**21.1**	19.3	57.2
	57.2	74.3	76.1
State –			
Current	**6.7**	7.7	3.6
Deferred	**12.9**	3.7	13.2
	19.6	11.4	16.8
Total	**$ 76.8**	$ 85.7	$ 92.9

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, were as follows:

	2010	2009
	(in millions)	
Deferred tax liabilities–		
Accelerated depreciation and other property basis differences	**$ 348.8**	$ 303.9
Basis difference on asset transfers	**3.5**	3.9
Other	**-**	-
Total	**352.3**	307.8
Deferred tax assets–		
Federal effect of state deferred taxes	**18.4**	13.7
Net basis difference on convertible investment tax credits	**9.5**	2.9
Basis differences on asset transfers	**5.9**	6.7
Other comprehensive loss on interest rate swaps	**24.4**	28.1
Levelized capacity revenues	**12.7**	15.2
Other	**3.4**	1.7
Total	**74.3**	68.3
Total deferred tax liabilities, net	**278.0**	239.5
Portion included in current income taxes	**(0.6)**	(1.2)
Accumulated deferred income taxes	**$ 277.4**	$ 238.3

Deferred tax liabilities are the result of property related timing differences. The transfer of the Plant McIntosh construction project to GPC in 2004 resulted in a deferred gain for federal income tax purposes. GPC is reimbursing the Company for the related tax liability balance of $3.5 million. Of this total, $0.3 million is included in the balance sheets in “Receivables – Affiliated companies” and the remainder is included in “Other deferred charges and assets – affiliated.”

Deferred tax assets consist primarily of timing differences related to the recognition of capacity revenues and the deferred loss on interest rate swaps reflected in OCI. The transfer of Plants Dahlberg, Wansley, and Franklin to the Company from GPC in 2001 also resulted in a deferred gain for federal income tax purposes. The Company will reimburse GPC for the related tax asset of $5.9 million. Of this total, $1.3 million is included in the balance sheets in “Accounts payable – Affiliated” and the remainder is included in “Other deferred credits and liabilities – affiliated.”

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 tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2010	2009	2008
Federal statutory rate	**35%**	35.0%	35.0%
State income tax, net of federal deduction	**6.2**	3.1	4.6
ITC basis difference	**(3.4)**	(1.2)	-
Other	**(0.7)**	(1.4)	(0.4)
Effective income tax rate	**37.1**	35.5%	39.2%

The Company’s effective tax rate increased primarily as a result of an increase in Alabama state taxes. Alabama’s state tax liability is reduced by a deduction for federal income taxes paid. Due to increased bonus depreciation and incentives associated with new plant construction, the federal tax liability was significantly reduced, resulting in a higher overall state tax expense. Also contributing to the increase in state taxes was the application of the resulting higher state tax rate to the deferred income tax balance.

Convertible ITCs received in 2010 for the construction of Plant Nacogdoches were $26.4 million; the tax benefit of the basis difference reduced income tax expense by $6.9 million. See Note 1 under “Convertible Investment Tax Credits” for additional information.

Convertible ITCs received in 2009 for the construction of Plant Nacogdoches were $16.8 million; the tax benefit of the basis difference reduced income tax expense by $2.9 million.

Unrecognized Tax Benefits

For 2010, the total amount of unrecognized tax benefits increased $2.2 million, resulting in a balance of $2.3 million as of December 31, 2010.

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

	2010	2009	2008
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 0.1**	$ 0.5	$ 1.4
Tax positions from current periods	**0.7**	0.3	0.3
Tax positions from prior periods	**1.5**	(0.7)	0.1
Reductions due to settlements	**-**	-	(1.3)
Reductions due to expired statute of limitations	**-**	-	-
Balance at end of year	**$ 2.3**	$ 0.1	$ 0.5

The tax positions increase from current and prior periods relate 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, is as follows:

	2010	2009	2008
		(in millions)	
Tax positions impacting the effective tax rate	**$ 0.6**	$ 0.1	$ 0.5
Tax positions not impacting the effective tax rate	**1.7**	-	-
Balance of unrecognized tax benefits	**$ 2.3**	$ 0.1	$ 0.5

The tax positions impacting the effective tax rate primarily relate to miscellaneous uncertain tax positions. 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 millions)	
Interest accrued at beginning of year	**$ -**	$ -	$ 0.1
Interest reclassified due to settlements	**-**	-	(0.1)
Interest accrued during the year	**-**	-	-
Balance at end of year	**$ -**	$ -	$ -

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

Senior Notes

In 2010 and 2009, the Company did not issue or redeem any long-term debt securities. Long-term debt outstanding was $1.3 billion at December 31, 2010 and 2009.

Bank Credit Arrangements

The Company has a $400 million unsecured syndicated revolving credit facility (Facility) expiring in July 2012. The purpose of the Facility is to provide liquidity support to the Company's commercial paper program and for other general corporate purposes. There were no borrowings outstanding under the Facility at December 31, 2010 and 2009.

The Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than $^{1}/_{10}$ of 1%.

The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65%. The Facility also contains a cross default provision that would be triggered if the Company defaulted on other indebtedness above a specified threshold. As of December 31, 2010, the Company was in compliance with all such covenants.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. During 2010, the Company had an average of $169 million of commercial paper outstanding at a weighted average interest rate of 0.4% per annum and the maximum amount outstanding was $259 million. At December 31, 2010, the Company had $204 million of commercial paper outstanding. During 2009, the Company had an average of $7 million of commercial paper outstanding at a weighted average interest rate of 0.4% per annum. At December 31, 2009, the Company had $119 million of commercial paper outstanding. The maximum amount outstanding during 2009 was $119 million.

Dividend Restrictions

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

The Facility and the indenture related to certain series of the Company's senior notes also contain certain limitations on the payment of common stock dividends. No dividends may be paid unless, as of the end of any calendar quarter, the Company's projected cash flows from fixed priced capacity PPAs are at least 80% of total projected cash flows for the next 12 months or the Company's debt to capitalization ratio is no greater than 60%. At December 31, 2010, the Company was in compliance with these ratios and had no other restrictions on its ability to pay dividends.

7. COMMITMENTS

Expansion Program

The capital program of the Company is currently estimated to be $540 million for 2011, $144 million for 2012, and $37 million for 2013. These amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements. Planned expenditures for plant acquisitions may vary due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

Long-Term Service Agreements

The Company has entered into long-term service agreements (LTSAs) with General Electric and Siemens AG for the purpose of securing maintenance support for its combined cycle and combustion turbine generating facilities. In summary, the LTSAs provide that the vendors will perform all planned inspections and certain unplanned maintenance on the covered equipment, which includes the cost of all labor and materials.

Scheduled payments to the vendors, which are subject to price escalation, are made at various intervals based on actual operating hours or number of gas turbine starts of the respective units. Total remaining payments to the vendors under these agreements are currently estimated at $1.1 billion over the remaining term of the agreements, which may range up to 23 years. However, the LTSAs contain various cancellation provisions at the Company's and the applicable vendor's option. In the event of cancellation prior to scheduled work being performed, the Company is entitled to a refund of amounts paid as calculated in accordance with termination provisions of the agreements.

Payments made to the vendors prior to the performance of any planned inspections or unplanned maintenance are recorded as a prepayment in current assets or deferred charges and other assets on the balance sheets and are recorded as payments pursuant to long-term service agreements in the statements of cash flows. All work performed is capitalized or charged to expense as appropriate based on the nature of the work when performed; therefore, these charges are non-cash and are not reflected in the statements of cash flows.

Fuel and Purchased Power Commitments

SCS, as agent for the traditional operating companies and the Company, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the operating facilities. In most cases, these contracts contain provisions for firm transportation costs, storage costs, minimum purchase levels, and other financial commitments. 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 the New York Mercantile Exchange future prices at December 31, 2010. Also, the Company has entered into various long-term commitments for the purchase of biomass fuel for the biomass generating plant being constructed by the Company and for the purchase of electricity.

Total estimated minimum long-term commitments at December 31, 2010 were as follows:

	Natural Gas Commitments	Biomass Fuel Commitments	Purchased Power Commitments[(a)]
		(in millions)	
2011	$ 338.2	$ -	$ 7.8
2012	284.5	14.5	49.2
2013	201.4	17.5	50.4
2014	154.8	17.8	51.6
2015	140.4	18.2	53.5
2016 and beyond	229.2	110.0	241.7
Total	$ 1,348.5	$ 178.0	$ 454.2

(a) Represents contractual capacity payments.

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

The Company has entered into agreements to purchase 380 MWs of power from two counterparties. Approximately 280 MWs of the commitment obligations from one counterparty will be used to serve the Company's requirements service customers. Another agreement for 100 MWs will be resold to EnergyUnited Electric Membership Corporation (EnergyUnited) at cost for the period 2012 through 2021. The purchase power commitments for the EnergyUnited agreement are $35.4 million in 2012, $36.1 million in 2013, $36.8 million in 2014, $37.6 million in 2015, and $241.7 million in 2016 and beyond.

In addition, the Company has entered into an agreement to purchase power of up to 200 MWs at the discretion of the counterparty for the period 2011 through 2018. There is no contractual capacity payment required under this agreement. Additionally, for all amounts purchased under this arrangement, the Company will pay the counterparty an amount per MW which approximates the Company's cost.

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

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total operating lease expenses were $0.5 million, $0.5 million, and $0.5 million for 2010, 2009, and 2008, respectively. The majority of the lease expense amounts and committed future expenditures are with a joint owner of Plant Stanton Unit A.

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

	Operating Lease Commitments
	(in millions)
2011	$ 0.5
2012	0.5
2013	0.5
2014	0.5
2015	0.4
2016 and beyond	22.3
Total	$ 24.7

8. 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. The need to use unobservable inputs would typically apply to long-term energy-related derivative contracts and generally results from the nature of the energy industry, as each participant forecasts its own power supply and demand and those of other participants, which directly impact the valuation of each unique contract.

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 millions)		
Assets:				
Energy-related derivatives	$ -	$ 2.8	$ -	$ 2.8
Cash equivalents	7.2	-	-	7.2
Total	$7.2	$ 2.8	$ -	$10.0
Liabilities:				
Energy-related derivatives	$ -	$ 6.2	$ -	$ 6.2

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 9 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 millions*)			
Cash equivalents:				
Money market funds	$7.2	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 Securities and Exchange Commission 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 millions)	
Long-term debt:		
2010	**$1,298**	**$1,378**
2009	$1,298	$1,379

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

9. 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. The Company has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price or heat rate 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:

- *Cash Flow Hedges* **–** Gains and losses on energy-related derivatives designated as cash flow hedges, which are used to hedge anticipated purchases and sales are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* **–** Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2010, the net volume of energy-related derivative contracts for power and natural gas positions for the Company, together with the longest hedge date over which the Company 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:

Power			Gas		
Net Sold Megawatt-hours	**Longest Hedge Date**	**Longest Non-Hedge Date**	**Net Purchased mmBtu***	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in millions)			*(in millions)*		
0.9	2011	2011	13	2012	2015

*million British thermal units

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

For the next 12-month period ending December 31, 2011, the Company expects to reclassify $1.0 million in losses from OCI to fuel expense with respect to cash flow hedges.

Interest Rate Derivatives

The Company also enters into interest rate derivatives from time to time 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.

The estimated pre-tax loss that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2011 is $11.5 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2016.

Derivative Financial Statement Presentation and Amounts

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

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2010**	2009	**Balance Sheet Location**	**2010**	2009
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments in cash flow hedges						
Energy-related derivatives:	Assets from risk management activities	**$ 0.1**	$ 3.2	Liabilities from risk management activities	**$ 1.0**	$ 5.3
	Other deferred charges and assets – non-affiliated	**-**	-	Other deferred credits and liabilities – non-affiliated	**-**	0.4
Total derivatives designated as hedging instruments in cash flow hedges		**$ 0.1**	$ 3.2		**$ 1.0**	$ 5.7
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Assets from risk management activities	**$ 2.1**	$ 1.7	Liabilities from risk management activities	**$ 4.8**	$ 2.8
	Other deferred charges and assets – non-affiliated	**0.6**	0.2	Other deferred credits and liabilities – non-affiliated	**0.4**	0.1
Total derivatives not designated as hedging instruments		**$ 2.7**	$ 1.9		**$ 5.2**	$ 2.9
Total		**$ 2.8**	$ 5.1		**$ 6.2**	$ 8.6

All derivative instruments are measured at fair value. See Note 8 for additional information.

For the years ended December 31, 2010, 2009, and 2008, the pre-tax effect of energy-related derivatives and 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 millions)				*(in millions)*	
Energy-related derivatives	**$1.5**	$(1.7)	$0.9	Depreciation and amortization	**$ 0.4**	$ 0.4	$ 0.4
Interest rate derivatives	**-**	-	-	Interest expense, net of amounts capitalized	**(10.8)**	(10.0)	(12.0)
Total	**$1.5**	$(1.7)	$0.9		**$(10.4)**	$ (9.6)	$(11.6)

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 as follows:

Derivatives not Designated as Hedging Instruments	**Unrealized Gain (Loss) Recognized in Income**			
			Amount	
Derivative Category	**Statements of Income Location**	**2010**	2009	2008
			(in millions)	
Energy-related derivatives:	Wholesale revenues, non-affiliates	**$(1.5)**	$ 5.3	$(1.9)
	Fuel	**0.7**	(6.0)	5.1
	Purchased power, non-affiliates	**(0.7)**	(4.5)	(2.3)
Total		**$(1.5)**	$(5.2)	$ 0.9

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 $2.6 million.

At December 31, 2010, the Company had no collateral posted with their 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. Included in these amounts are certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade.

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2010 and 2009 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income
		(in thousands)	
March 2010	**$ 256,488**	**$ 43,928**	**$ 14,810**
June 2010	**248,476**	**59,131**	**29,704**
September 2010	**356,830**	**111,925**	**61,694**
December 2010	**267,351**	**67,810**	**23,814**
March 2009	$ 231,517	$ 66,981	$ 27,916
June 2009	230,598	73,276	31,054
September 2009	283,369	127,165	67,280
December 2009	201,168	46,134	29,602

The Company's business is influenced by seasonal weather conditions. Fourth quarter 2009 net income includes profit recognized on the OUC construction contract of $10.6 million pretax and $6.5 million after tax.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2006-2010

Southern Power Company and Subsidiary Companies 2010 Annual Report

	2010	2009	2008	2007	2006
Operating Revenues (in thousands)**:**					
Wholesale - non-affiliates	**$751,575**	$394,366	$667,979	$416,648	$279,384
Wholesale - affiliates	**370,630**	544,415	638,266	547,229	491,762
Total revenues from sales of electricity	**1,122,205**	938,781	1,306,245	963,877	771,146
Other revenues	**6,940**	7,870	7,296	8,137	5,902
Total	**$1,129,145**	$946,651	$1,313,541	$972,014	$777,048
Net Income (in thousands)	**$130,022**	$155,852	$144,359	$131,637	$124,469
Cash Dividends					
on Common Stock (in thousands)	**$107,100**	$ 106,100	$ 94,500	$ 89,800	$ 77,700
Return on Average Common Equity (percent)	**10.71**	13.36	13.03	12.52	13.16
Total Assets (in thousands)	**$3,276,351**	$3,043,053	$2,813,140	$2,768,774	$2,690,943
Gross Property Additions/Plant Acquisitions (in thousands)	**$299,602**	$331,289	$49,964	$139,198	$465,026
Capitalization (in thousands)**:**					
Common stock equity	**$1,232,085**	$1,195,122	$1,138,361	$1,077,887	$1,025,504
Long-term debt	**1,297,860**	1,297,607	1,297,353	1,297,099	1,296,845
Total (excluding amounts due within one year)	**$2,529,945**	$2,492,729	$2,435,714	$2,374,986	$2,322,349
Capitalization Ratios (percent)**:**					
Common stock equity	**48.7**	47.9	46.7	45.4	44.2
Long-term debt	**51.3**	52.1	53.3	54.6	55.8
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Kilowatt-Hour Sales (in thousands)**:**					
Wholesale - non-affiliates	**13,285,465**	7,513,569	7,573,713	6,985,592	5,093,527
Wholesale - affiliates	**10,494,339**	12,293,585	9,402,020	10,766,003	8,493,441
Total	**23,779,804**	19,807,154	16,975,733	17,751,595	13,586,968
Average Revenue Per Kilowatt-Hour (cents)	**4.72**	4.74	7.69	5.43	5.68
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**7,880**	7,880	7,555	6,896	6,733
Maximum Peak-Hour Demand (megawatts)**:**					
Winter	**3,295**	3,224	3,042	2,815	2,780
Summer	**3,543**	3,308	3,538	3,717	2,869
Annual Load Factor (percent)	**54.0**	52.6	50.0	48.2	53.6
Plant Availability (percent)	**94.0**	96.7	96.0	96.7	98.3
Source of Energy Supply (percent)**:**					
Gas	**88.8**	84.4	75.6	70.4	68.3
Purchased power -					
From non-affiliates	**5.5**	7.9	11.3	8.8	9.6
From affiliates	**5.7**	7.7	13.1	20.8	22.1
Total	**100.0**	100.0	100.0	100.0	100.0

PART III

Items 10, 11, 12, 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2011 Annual Meeting of Stockholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation," and "Director Compensation Table" for Item 11, "Stock Ownership Table" and "Equity Compensation Plan Information" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13, and 14 for Alabama Power, Georgia Power, and Mississippi Power are incorporated by reference to the Definitive Information Statements of Alabama Power, Georgia Power, and Mississippi Power relating to each of their respective 2011 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation Information," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13, and 14 for Gulf Power are contained herein.

Items 10, 11, 12 and 13 for Southern Power are omitted pursuant to General Instruction I(2)(c) of Form 10-K. Item 14 for Southern Power is contained herein.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of directors of Gulf Power.

Mark A. Crosswhite ***(1)*** **President and Chief Executive Officer** **Age 48** **Served as Director since 2011**	**J. Mort O'Sullivan, III** ***(2)*** **Age 59** **Served as Director since 2010**
Allan G. Bense ***(2)*** **Age 59** **Served as Director since 2010**	**William A. Pullum** ***(2)*** **Age 63** **Served as Director since 2001**
Deborah H. Calder ***(2)*** **Age 50** **Served as Director since 2010**	**Winston E. Scott** ***(2)*** **Age 60** **Served as Director since 2003**
William C. Cramer, Jr. ***(2)*** **Age 58** **Served as Director since 2002**	

(1) On November 15, 2010, the Gulf Power board of directors elected Mr. Crosswhite as President and Chief Executive Officer, effective on January 1, 2011.
(2) No position other than director.

Each of the above is currently a director of Gulf Power, serving a term running from the last annual meeting of Gulf Power's shareholders (June 29, 2010) for one year until the next annual meeting or until a successor is elected and qualified, except for Mr. Crosswhite, whose election was effective January 1, 2011.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as a director, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of executive officers of Gulf Power.

Mark A. Crosswhite **President and Chief Executive Officer** **Age 48** **Served as Executive Officer since 2011**	**Michael L. Burroughs** **Vice President – Senior Production Officer** **Age 50** **Served as Executive Officer since 2010**
P. Bernard Jacob **Vice President – Customer Operations** **Age 56** **Served as Executive Officer since 2003**	**Bentina C. Terry** **Vice President – External Affairs and Corporate Services** **Age 40** **Served as Executive Officer since 2007**
Richard S. Teel **Vice President and Chief Financial Officer** **Age 40** **Served as Executive Officer since 2010**	

Each of the above is currently an executive officer of Gulf Power, serving a term, until the next annual organizational meeting or until a successor is elected and qualified. Mr. Jacob and Ms. Terry were elected at the annual organizational meeting of the directors on July 22, 2010 and Messrs. Burroughs, Teel, and Crosswhite were elected effective August 1, 2010, August 13, 2010, and January 1, 2011, respectively.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as an officer, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of certain significant employees. *None.*

Family relationships. *None.*

Business experience. *Unless noted otherwise, each director has served in his or her present position for at least the past five years.*

<u>*DIRECTORS*</u>

Gulf Power's Board of Directors possesses collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and Gulf Power's industry.

Mark A. Crosswhite – President and Chief Executive Officer of Gulf Power since January 1, 2011. Mr. Crosswhite previously served as Executive Vice President of External Affairs of Alabama Power from February 2008 through December 2010 and as Senior Vice President and Counsel of Alabama Power from July 2006 through January 2008. He also served as Vice President of SCS from March 2004 through January 2008.

Allan G. Bense - Panama City businessman and former Speaker of the Florida House of Representatives. Mr. Bense is a partner in several companies involved in road building, mechanical contracting, insurance, general contracting, golf courses and farming and represented the Bay County area in the Florida House of Representatives beginning in 1998 and served as Speaker of the House from 2004-2006. Mr. Bense has also served as Vice Chair of Enterprise Florida, the economic development agency for the state from January 2009 to January 2011.

Deborah H. Calder - Senior Vice President for Navy Federal Credit Union since June 2008. Since September 2007, Ms. Calder has directed the day-to-day operations of more than 1,400 employees and the ongoing construction of Navy Federal Credit Union's campus in the Pensacola area. Ms. Calder has been with Navy Federal Credit Union for over 18 years, serving in previous positions as Vice President of Consumer and Credit Card Lending, Vice President of Collections, Vice President of Call Center Operations and Assistant Vice President of Credit Cards.

William C. Cramer, Jr. - President and Owner of automobile dealerships in Florida, Georgia, and Alabama. Mr. Cramer has been an authorized Chevrolet dealer since 1978. In 2009, Mr. Cramer became an authorized dealer of

Cadillac, Buick, and GMC vehicles.

J. Mort O'Sullivan, III – Managing Partner of O'Sullivan Creel, LLP, an accounting firm originally formed as O'Sullivan Patton Jacobi in 1981. Mr. O'Sullivan currently focuses on consulting and management advisory services to clients, while continuing to offer his expertise in litigation support, business valuations, and mergers and acquisitions. He is a registered investment advisor.

William A. Pullum – President and Director of Bill Pullum Realty, Inc., Navarre, Florida. Mr. Pullum is also a real estate developer.

Winston E. Scott – Dean, College of Aeronautics, Florida Institute of Technology, Melbourne, Florida since August 2008. He previously served as Vice President and Deputy General Manager, Engineering and Science Contract Group at Jacobs Engineering, Houston, Texas, from September 2006 through July 2008. Mr. Scott's experience also included serving as a pilot in the U.S. Navy, an astronaut with the National Aeronautic and Space Administration and as executive director of the Florida Space Authority.

EXECUTIVE OFFICERS

Michael L. Burroughs – Vice President and Senior Production Officer since August 2010. He previously served as Manager of Georgia Power's Plant Yates from September 2007 to July 2010 and as Assistant to the Chief Production Officer of SCS Generation from May 2006 to August 2007.

P. Bernard Jacob – Vice President of Customer Operations since 2007. He previously served as Vice President of External Affairs and Corporate Services from 2003 to 2007.

Richard S. Teel - Vice President and Chief Financial Officer since August 2010. He previously served as Vice President and Chief Financial Officer of Southern Company Generation, a business unit of Southern Company, from January 2007 to July 2010 and as Assistant to the Executive Vice President and Chief Financial Officer of Southern Company from July 2005 to January 2007.

Bentina C. Terry – Vice President of External Affairs and Corporate Services since 2007. She previously served as General Counsel and Vice President of External Affairs for Southern Nuclear from January 2005 to March 2007.

Involvement in certain legal proceedings. None.

Promoters and Certain Control Persons. None.

Section 16(a) Beneficial Ownership Reporting Compliance. None.

Code of Ethics

The registrants collectively have adopted a code of business conduct and ethics that applies to each director, officer, and employee of the registrants and their subsidiaries. The code of business conduct and ethics can be found on Southern Company's website located at www.southerncompany.com. The code of business conduct and ethics is also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Assistant Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Any amendment to or waiver from the code of ethics that applies to executive officers and directors will be posted on the website.

Corporate Governance

Southern Company has adopted corporate governance guidelines and committee charters. The corporate governance guidelines and the charters of Southern Company's Audit Committee, Compensation and Management Succession Committee, Finance Committee, Governance Committee, and Nuclear/Operations Committee can be found on Southern Company's website located at www.southerncompany.com. The corporate governance guidelines and charters are also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Assistant Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

ITEM 11. EXECUTIVE COMPENSATION

GULF POWER

COMPENSATION DISCUSSION AND ANALYSIS (CD&A)

In this CD&A and this Form 10-K, references to the "Compensation Committee" are to the Compensation and Management Succession Committee of the Board of Directors of Southern Company.

This section describes the compensation program for Gulf Power's Chief Executive Officer and Chief Financial Officer in 2010, as well as each of Gulf Power's other three most highly compensated executive officers employed at the end of the year.

Susan N. Story	President and Chief Executive Officer
Richard S. Teel	Vice President and Chief Financial Officer
Michael L. Burroughs	Vice President
Paul B. Jacob	Vice President
Bentina C. Terry	Vice President

Additionally, we describe the compensation of Gulf Power's former Vice President and Chief Financial Officer, Philip C. Raymond, who transferred to Alabama Power on August 13, 2010, and Theodore J. McCullough, Gulf Power's former Vice President who transferred to Alabama Power on June 30, 2010. Collectively, the officers listed above and these officers are referred to as Gulf Power's named executive officers.

Executive Summary

Performance

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to Gulf Power's named executive officers for 2010.

	Salary ($)(1)	% of Total	Short-Term Performance Pay ($)(1)	% of Total	Long-Term Performance Pay ($)(1)	% of Total
S. N. Story	420,643	36	297,463	26	440,816	38
R. S. Teel	205,540	51	122,771	30	78,752	19
P. C. Raymond	245,106	44	169,905	31	141,829	25
M. L. Burroughs	150,745	58	86,925	34	20,155	8
P. B. Jacob	239,444	47	128,385	25	143,027	28
T. J. McCullough	201,212	49	132,567	33	75,377	18
B. C. Terry	237,466	47	127,352	25	141,829	28

(1) Salary is the actual amount paid in 2010; Short-Term Performance Pay is the actual amount earned in 2010 based on performance; and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2010. See the Summary Compensation table herein for the amounts of all elements of reportable compensation as described in this CD&A.

Operational, business unit financial, and Southern Company earnings per share goal results for 2010 and relative total shareholder return of Southern Company for the four-year measurement period that ended in 2010 are shown below.

Business unit financial goals:	88% of Target
Southern Company earnings per share:	155% of Target
Operational goals:	104% of Target
Relative total shareholder return:	106% of Target

These levels of achievement resulted in actual payouts that exceeded targets. Southern Company's total shareholder return has been:

1-year: 20.8%
3-year: 4.8%
5-year: 7.1%

Pay Philosophy

Our compensation program (salary and short- and long-term performance pay) is based on the philosophy that total compensation should be:

- competitive with the companies in our industry;
- tied to and structured to motivate achievement of short- and long-term business goals; and
- aligned with the interests of Gulf Power's customers and Southern Company's stockholders.

Competitive with the companies in our industry

Executive compensation is targeted at the market median of industry peers. Actual compensation is primarily determined by short- and long-term financial and operational performance.

Motivates and rewards achievement of short- and long-term business goals

Our business goals are simple. Financial success is tied directly to the satisfaction of customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. We believe that our focus on the customer helps us achieve our financial objectives and deliver a premium, risk-adjusted total shareholder return to stockholders.

Aligned with the interests of stockholders and customers

Our short-term performance pay is based on achievement of our business goals, with one-third determined by operational performance, such as safety, reliability, and customer satisfaction; one-third determined by business unit financial performance; and one-third determined by Southern Company earnings per share performance.

Our long-term performance pay is tied directly to stockholder value with 40% of the target value awarded in Southern Company stock options, which reward stock price appreciation, and 60% awarded in performance share units, which reward total shareholder return performance relative to that of our peers.

Key Governance and Pay Practices

- Annual pay risk assessment required by the Compensation Committee charter.
- Retention of an independent consultant, Pay Governance LLC, that provides no other services to Southern Company.
- Inclusion of a claw-back provision that permits the Compensation Committee to recoup performance pay from any employee if determined to have been based on erroneous results, and requires recoupment from an executive officer in the event of material financial restatement due to fraud or misconduct of the executive officer.
- Elimination of excise tax gross-up on change-in-control severance arrangements.
- Provision of limited perquisites.
- "No-hedging" provision in the insider trading policy that is applicable to all employees.
- Strong stock ownership requirements that are being met by all named executive officers.

GUIDING PRINCIPLES AND POLICIES

Southern Company, through a single compensation program for all officers of its subsidiaries, drives and rewards both Southern Company financial performance and individual business unit performance. This executive compensation program is based on a philosophy that total executive compensation must be competitive with the companies in our industry, must be tied to and motivate our executives to meet our short- and long-term performance goals, must foster and encourage alignment of executive interests with the interests of Southern Company's stockholders and our customers, and must not encourage excessive risk-taking. The program generally is designed to motivate all employees, including executives, to achieve operational excellence and financial goals while maintaining a safe work environment.

Our executive compensation program places significant focus on rewarding performance. The program is performance-based in several respects:

- Southern Company's actual earnings per share (EPS) and Gulf Power's business unit performance, which includes return on equity (ROE), and operational performance compared to target performance levels established early in the year, determine the actual payouts under the short-term (annual) performance-based compensation program (Performance Pay Program).

- Southern Company common stock (Common Stock) price changes result in higher or lower ultimate values of stock options.

- Southern Company's total shareholder return compared to those of industry peers lead to higher or lower payouts under the Performance Share Program (performance shares).

In support of our performance-based pay philosophy, we have no general employment contracts or guaranteed severance with our named executive officers, except upon a change in control.

The pay-for-performance principles apply not only to the named executive officers, but to hundreds of Gulf Power employees. The Performance Pay Program covers almost all of the approximately 1,300 Gulf Power employees. Stock options and performance shares cover over 100 employees. These programs engage our people in our business, which ultimately is good not only for them, but for Gulf Power's customers and Southern Company's stockholders.

OVERVIEW OF EXECUTIVE COMPENSATION COMPONENTS

Our executive compensation program has several components, each of which plays a different role. The chart below discusses the intended role of each material pay component, what it rewards, and why we use it. Following the chart is additional information that describes how we made 2010 pay decisions.

Pay Element	Intended Role and What the Element Rewards	Why We Use the Element
Base Salary	Base salary is pay for competence in the executive role, with a focus on scope of responsibilities.	Market practice. Provides a threshold level of cash compensation for job performance.
Annual Performance-Based Compensation: Performance Pay Program	The Performance Pay Program rewards achievement of operational, EPS, and business unit financial goals.	Market practice. Focuses attention on achievement of short-term goals that ultimately work to fulfill our mission to customers and lead to increased stockholder value in the long term.

Pay Element	Intended Role and What the Element Rewards	Why We Use the Element
Long-Term Performance-Based Compensation: Stock Options	Stock options reward price increases in Common Stock over the market price on the date of grant, over a 10-year term.	Market practice. Performance-based compensation. Aligns executives' interests with those of Southern Company's stockholders.
Long-Term Performance-Based Compensation: Performance Shares	Performance shares provide equity compensation dependent on Southern Company's three-year total shareholder return versus industry peers.	Market practice. Performance-based compensation. Aligns executives' interests with Southern Company's stockholders' interests since payouts are dependent on the returns realized by Southern Company's stockholders versus those of industry peers.
Long-Term Equity Compensation: Restricted Stock Units	Restricted stock units are payable in Common Stock at the end of three years and deemed dividends are reinvested.	Limited use of restricted stock units to address specific needs, including retention. Aligns executive's interest with stockholders' interests.
Retirement Benefits	Executives participate in employee benefit plans available to all employees of Gulf Power, including a 401(k) savings plan and the funded Southern Company Pension Plan (Pension Plan). The Southern Company Deferred Compensation Plan provides the opportunity to defer to future years up to 50% of base salary and all or part of performance-based compensation, except stock options, in either a prime interest rate or Common Stock account. The Supplemental Benefit Plan counts pay, including deferred salary, ineligible to be counted under the Pension Plan and the 401(k) plan due to Internal Revenue Service rules. The Supplemental Executive Retirement Plan counts annual performance-based pay above 15% of base salary for pension purposes. To retain mid-career hires, supplemental retirement agreements give pension credit for years of relevant experience prior to employment with Gulf Power or its affiliates.	Represents an important component of competitive market-based compensation in both our peer group and generally. Permitting compensation deferral is a cost-effective method of providing additional cash flow to Gulf Power while enhancing the retirement savings of executives. The purpose of these supplemental plans is to eliminate the effect of tax limitations on the payment of retirement benefits. .

Pay Element	Intended Role and What the Element Rewards	Why We Use the Element
Perquisites and Other Personal Benefits	Personal financial planning maximizes the perceived value of our executive compensation program to executives and allows them to focus on Gulf Power's operations. Home security systems lower the risk of harm to executives. (*Eliminated effective 2011.)* Club memberships are provided primarily for business use. (*Payment of dues eliminated effective 2011.)* Limited personal use of corporate-owned aircraft associated with business travel. Relocation benefits cover the costs associated with geographic relocations at the request of the employer. For the President and Chief Executive Officer tax gross-ups are not provided on any perquisites except relocation benefits.	Our remaining limited perquisites represent an effective, low-cost means to retain key talent.
Severance Arrangements	Change-in-control agreements provide severance pay, accelerated vesting, and payment of short- and long-term performance-based compensation upon a change in control of Gulf Power or Southern Company coupled with involuntary termination not for cause or a voluntary termination for "Good Reason."	Market practice. Providing protections to officers upon a change in control minimizes disruption during a pending or anticipated change in control. Payment and vesting occur only upon the occurrence of both an actual change in control and loss of the executive's position.

MARKET DATA

For the named executive officers, the Compensation Committee reviews compensation data from large, publicly-owned electric and gas utilities. The data was developed and analyzed by Pay Governance LLC, the compensation consultant retained by the Compensation Committee. The companies included each year in the primary peer group are those whose data is available through the consultant's database. Those companies are drawn from this list of primarily regulated utilities of $2 billion in revenues and up.

AGL Resources Inc.	El Paso Corporation	PG&E Corporation
Allegheny Energy, Inc.	Entergy Corporation	Pinnacle West Capital Corporation
Alliant Energy Corporation	EPCO	PPL Corporation
Ameren Corporation	Exelon Corporation	Progress Energy, Inc.
American Electric Power Company, Inc.	FirstEnergy Corp.	Public Service Enterprise Group Inc.
Atmos Energy Corporation	Integrys Energy Company, Inc.	Puget Energy, Inc.
Calpine Corporation	MDU Resources, Inc.	Reliant Energy, Inc.
CenterPoint Energy, Inc.	Mirant Corporation	Salt River Project
CMS Energy Corporation	New York Power Authority	SCANA Corporation
Consolidated Edison, Inc.	NextEra Energy, Inc.	Sempra Energy
Constellation Energy Group, Inc.	Nicor, Inc.	Southern Union Company
CPS Energy	Northeast Utilities	Spectra Energy
DCP Midstream	NRG Energy, Inc.	TECO Energy
Dominion Resources Inc.	NSTAR	Tennessee Valley Authority
Duke Energy Corporation	NV Energy, Inc.	The Williams Companies, Inc.
Dynegy Inc.	OGE Energy Corp.	Wisconsin Energy Corporation
Edison International	Pepco Holdings, Inc.	Xcel Energy Inc.

Southern Company is one of the largest utility companies in the United States based on revenues and market capitalization, and its largest business units are some of the largest in the industry as well. For that reason, the consultant size-adjusts the survey market data in order to fit it to the scope of our business.

In using this market data, market is defined as the size-adjusted 50th percentile of the survey data, with a focus on pay opportunities at target performance (rather than actual plan payouts). Market data for chief executive officer positions and other positions in terms of scope of responsibilities that most closely resemble the positions held by the named executive officers are reviewed. Based on that data, a total target compensation opportunity is established for each named executive officer. Total target compensation opportunity is the sum of base salary, annual performance-based compensation at the target performance level, and long-term performance-based compensation (stock options and performance shares) at a target value. Actual compensation paid may be more or less than the total target compensation opportunity based on actual performance above or below target performance levels. As a result, the compensation program is designed to result in payouts that are market-appropriate given Gulf Power's and Southern Company's performance for the year or period.

We did not target a specified weight for base salary or annual or long-term performance-based compensation as a percentage of total target compensation opportunities, nor did amounts realized or realizable from prior compensation serve to increase or decrease 2010 compensation amounts. Total target compensation opportunities for senior management as a group are managed to be at the median of the market for companies of our size and in our industry. The total target compensation opportunity established in early 2010 for each named executive officer is shown below.

	Salary ($)	Target Annual Performance-Based Compensation ($)	Target Long-Term Performance-Based Compensation ($)	Total Target Direct Compensation Opportunity ($)
S. N. Story	419,849	251,909	440,816	1,112,574
R. S. Teel	196,931	78,772	78,752	354,455
P. C. Raymond	236,428	106,393	141,829	484,650
M. L. Burroughs	134,558	47,095	20,155	202,808
P. B. Jacob	238,408	107,824	143,027	489,259
T. J. McCullough	194,116	77,646	75,377	347,139
B. C. Terry	236,428	106,393	141,829	484,650

As described above, in mid-2010, several organizational changes were made including changes affecting some of Gulf Power's named executive officers. As a result, Messrs. Burroughs, McCullough, Raymond, and Teel received annual salary rate increases to $174,925, $210,870, $258,132, and $220,562, respectively.

The 2010 salary reported in the Summary Compensation Table is the actual amount paid in 2010 and therefore will differ from the salary rates shown above due to rounding and pay dates.

For purposes of comparing the value of our compensation program to the market data, stock options are valued at $2.23 per option and performance shares at $30.13 per unit. These values represent risk-adjusted present values on the date of grant and are consistent with the methodologies used to develop the market data. The mix of stock options and performance shares granted were 40% and 60%, respectively, of the long-term value shown above.

As discussed above, the Compensation Committee targets total target compensation opportunities for senior executives as a group at market. Therefore, some executives may be paid somewhat above and others somewhat below market. This practice allows for minor differentiation based on time in the position, scope of responsibilities, and individual performance. The differences in the total pay opportunities for each named executive officer are based almost exclusively on the differences indicated by the market data for persons holding similar positions. The average total target compensation opportunities for the named executive officers for 2010 were at the median of the market data described above. Because of the use of market data from a large number of peer companies for positions that are not identical in terms of scope of responsibility from company to company, we do not consider slight differences material and continue to believe that our compensation program is market-appropriate. Generally, we consider compensation to be within an appropriate range if it is not more or less than 15% of the applicable market data.

In 2009, Towers Perrin, the former Compensation Committee consultant, analyzed the level of actual payouts, for 2008 performance, under the annual Performance Pay Program to the named executive officers relative to performance versus our peer companies to provide a check on Gulf Power's goal-setting process. The findings from the analyses were used in establishing performance goals and the associated range of payouts for goal achievement for 2010. That analysis was updated by Pay Governance LLC, the current Compensation Committee consultant. That analysis was updated in 2010 for 2009 performance, and those findings were used in establishing goals for 2011.

DESCRIPTION OF KEY COMPENSATION COMPONENTS

2010 Base Salary

Most employees, including a majority of the named executive officers, did not receive base salary increases in 2009. Southern Company's standard base salary program resumed in 2010 and most employees, including the named executive officers, received base salary increases, effective January 1, 2010.

With the exception of Ms. Story, the named executive officers are each within a position level with a base salary range that is established under the direction of the Compensation Committee using the market data described above. The actual base salary levels set for each of these named executive officers are within the pre-established salary ranges. Also considered in recommending the specific base salary level for each named executive officer is the need to retain an experienced team, internal equity, time in position, and individual performance. Individual performance includes the degree of competence and initiative exhibited and the individual's relative contribution to the results of operations in prior years. Ms. Story's total target compensation opportunity, including base salary, is not within a position level band. It is set directly by the Compensation Committee using the above-described market data for specific positions similar in scope and responsibility in the market peer companies listed above.

Base salaries for Ms. Terry and Messrs. Jacob, Raymond, and Teel were recommended by Ms. Story to Mr. David M. Ratcliffe, the now former Southern Company President and Chief Executive Officer. The base salaries for Messrs. Burroughs and McCullough, who both served as an executive officer of Gulf Power and of Southern Company's generation business unit (Southern Company Generation), were recommended by Mr. Thomas A. Fanning who, as Southern Company's then Chief Operating Officer, was the senior executive of Southern Company Generation, with input from Ms. Story. Ms. Story also is an executive officer of Southern Company. Her base salary was recommended by Mr. Ratcliffe to the Compensation Committee and was influenced by the above-described market data. The base salaries recommended by Ms. Story and Mr. Fanning were approved by Mr. Ratcliffe.

2010 Performance-Based Compensation

This section describes our performance-based compensation program in 2010. The Compensation Committee approved changes to the program that were implemented in 2010. The changes made to the program, and the rationale for the changes, are described below.

<u>Achieving Operational and Financial Goals — Our Guiding Principle for Performance-Based Compensation</u>

Our number one priority is to provide our customers outstanding reliability and superior service at low prices while achieving a level of financial performance that benefits Southern Company's stockholders in the short and long term.

In 2010, we strove for and rewarded:

- Continued industry-leading reliability and customer satisfaction, while maintaining our low retail prices relative to the national average; and

- Meeting energy demand with the best economic and environmental choices.

In 2010, we also focused on and rewarded:

- Southern Company earnings per share (EPS) growth;

- Gulf Power ROE, which is in the top quartile of comparable electric utilities;

- Southern Company dividend growth;

- Long-term, risk-adjusted Southern Company total shareholder return; and

- Financial integrity — an attractive risk-adjusted return, sound financial policy, and a stable “A” credit rating.

The performance-based compensation program is designed to encourage achievement of these goals.

The Southern Company Chief Executive Officer, with the assistance of Southern Company’s Human Resources staff, recommended to the Compensation Committee program design and award amounts for senior executives, including the named executive officers.

2010 Annual Performance Pay Program

Program Design

The Performance Pay Program is Gulf Power’s annual performance-based compensation program. Almost all employees of Gulf Power are participants, including the named executive officers, for a total of over 1,300 participants.

The performance measured by the program uses goals set at the beginning of each year by the Compensation Committee. Prior to 2010, the Performance Pay Program goals were weighted 50% Southern Company EPS and 50% business unit financial goals, primarily ROE. Operational goal achievement could adjust the total payout plus or minus 10%. The maximum payout that could be earned was 220% of target.

In 2009, the Compensation Committee approved changes to the program that were implemented in 2010. The primary changes to the program were to decrease the maximum opportunity from 220% of target to 200% of target and to increase the focus on operational performance. Excellent operational performance has always been a key focus of Gulf Power. We believe that financial success is tied directly to the satisfaction of customers and that operational excellence drives high customer satisfaction. The vast majority of employees do not have direct influence on financial performance, but they impact operational performance daily. We believe that it is important to match the importance of operational goal performance with the pay delivered for that performance. Therefore, in 2010, the Compensation Committee increased the weight of the operational goals to one-third in determining payouts under the Performance Pay Program. Southern Company EPS and business unit financial performance also are weighted one-third each. The results of each are added together to determine the total payout.

- For Southern Company’s traditional operating companies, operational goals are safety, customer satisfaction, plant availability, transmission and distribution system reliability, and culture.

- Southern Company EPS is defined as earnings from continuing operations divided by average shares outstanding during the year. The EPS performance measure is applicable to all participants in the Performance Pay Program.

- For Southern Company’s traditional operating companies, the business unit financial performance goal is ROE, which is defined as the traditional operating company’s net income divided by average equity for the year. For Southern Power, the business unit financial performance goal is net income.

- For Southern Company Generation, the operational goals are aggregated for all of the traditional operating companies. The business unit financial goal is based 90% on the aggregate ROE goal performance for the traditional operating companies and 10% on Southern Power net income.

Messes. Story and Terry and Mr. Jacob were employed by Gulf Power for all of 2010 and therefore their annual Performance Pay Program payout is calculated using ROE and operational goal achievement of Gulf Power. Mr. Raymond was employed by Gulf Power and Alabama Power during 2010 and therefore his payout is prorated based on goal achievement for Gulf Power and Alabama Power based on the period of service with each company. Mr. Burroughs was employed by Georgia Power and Southern Company Generation during 2010 and therefore his payout is prorated between goal achievement for Georgia Power and Southern Company Generation. For the portion of time Mr. Burroughs was with Southern Company Generation, it is prorated based 60% on Gulf Power results and 40% on Southern Company Generation results. Mr. McCullough was a Southern Company Generation employee for all of 2010; however, he served at both Gulf Power and Alabama Power for a portion of the year. Therefore, his payout is prorated 40% based on Southern Company Generation results and the remaining 60% is prorated based on Gulf Power and Alabama Power results. Mr. Teel was employed by Southern Company Generation and Gulf Power during 2010 and therefore his payout is prorated based on Southern Company Generation and Gulf Power results.

The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. Such adjustments include the impact of items considered non-recurring or outside of normal operations or not anticipated in the business plan when the earnings goal was established and of sufficient magnitude to warrant recognition. The Compensation Committee made an adjustment in 2010 to eliminate the positive effect of additional Southern Company net income in 2010 due to the tax deductibility of a portion of the settlement in 2009 related to the MC Asset Recovery, LLC (MCAR) litigation. As a result of this exclusion, the average Performance Pay Program payout was decreased by two percent of target. For 2009 payouts, the Compensation Committee had eliminated the negative effect of the settlement payment and therefore believed it was appropriate to eliminate the positive effect in 2010.

Under the terms of the program, no payout can be made if Southern Company's current earnings are not sufficient to fund the Common Stock dividend at the same level or higher than the prior year.

Goal Details

Operational Goals:

Customer Satisfaction —Customer satisfaction surveys evaluate performance. The survey results provide an overall ranking as well as a ranking for each customer segment: residential, commercial, and industrial.

Reliability — Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on recent historical performance.

Availability — Peak season equivalent forced outage rate is an indicator of availability and efficient generation fleet operations during the months when generation needs are greatest. Availability is measured as a percentage of the hours of forced outages out of the total generation hours.

Safety — Southern Company's Target Zero program is focused on continuous improvement in having a safe work environment. The performance is measured by the applicable company's ranking, as compared to peer utilities in the Southeast Electric Exchange.

Culture — The culture goal seeks to improve our inclusive workplace. This goal includes measures for work environment (employee satisfaction survey), representation of minorities and females in leadership roles (subjectively assessed), and supplier diversity.

Southern Company capital expenditures "gate" or threshold goal — Southern Company strived to manage total capital expenditures, excluding nuclear fuel, for the participating business units at or below $5.061 billion, and Gulf Power strived to manage such expenditures at or below $302 million. If the capital expenditure target is exceeded, this will result in a 10% of target reduction in the payouts under the Performance Pay Program. Adjustments to the goal may occur due to significant events not anticipated in the business plan established early in 2010, such as acquisitions or disposition of assets, new capital projects, and other events.

The ranges of performance levels established for the operational goals for the traditional operating companies are detailed below.

Level of Performance	Customer Satisfaction	Reliability	Availability	Safety	Culture
Maximum	Top quartile for each customer segment and overall	Highest performance	Industry best	Top 20th percentile	Significant improvement
Target	Top quartile overall	Average performance	Top quartile	Top 40th percentile	Improvement
Threshold	Median overall	Lowest performance	Median	Top 60th percentile	Significantly below expectations

The Compensation Committee approves specific objective performance schedules to calculate performance between the threshold, target, and maximum levels for each of the operational goals. Collectively, customer satisfaction, reliability, and availability are weighted 60% and safety and culture are weighted 20% each. If goal achievement is below threshold, there is no payout associated with the applicable goal.

Southern Company EPS and Business Unit Financial Performance:

The range of Southern Company EPS, ROE, and Southern Power net income goals for 2010 is shown below. ROE goals vary from the allowed retail ROE range due to state regulatory accounting requirements, wholesale activities, other non-jurisdictional revenues and expenses, and other activities not subject to state regulation.

Level of Performance	EPS ($)	ROE (%)	Southern Power Company Net Income ($) (millions)
Maximum	2.45	13.7	155
Target	2.33	11.9	135
Threshold	2.21	10.1	115

For 2010, the Compensation Committee established a minimum EPS performance that must be achieved. If Southern Company EPS is less than $2.10 (90% of Target), not only will there be no payout associated with EPS performance, but overall payouts under the Performance Pay Program will be reduced by 10% of target.

In setting the goals for pay purposes, the Compensation Committee relies on information from the Finance and Nuclear/Operations Committees of the Southern Company Board of Directors.

2010 Achievement

Each named executive officer had a target Performance Pay Program opportunity based on his or her position, set by the Compensation Committee at the beginning of 2010. Targets are set as a percentage of base salary. Ms. Story's target was set at 60%, and Ms. Terry's and Mr. Jacob's targets were set at 45%. For Mr. Burroughs, the target was set at 35% and increased to 40% due to his promotion. Messrs. McCullough's and Teel's targets were set at 40% and increased to 45% due to their promotions. Mr. Raymond's was set at 45% and increased to 50% due to his promotion. Actual payouts were determined by adding the payouts derived from the Southern Company EPS, and applicable operational and business unit financial performance goal achievement for 2010. The gate goal target was not exceeded and Southern Company EPS exceeded the minimum established and therefore payouts were not affected. Actual 2010 goal achievement is shown in the following tables. The EPS result shown in the table is adjusted for the 2010 impact of the tax deductibility of the MCAR settlement in 2010, as described above. Therefore, payouts were determined using EPS performance results that differed from the results reported in Southern Company's financial statements in Item 8 herein. EPS, as determined in accordance with generally accepted accounting principles in the United States and as reported by Southern Company, was $2.37 per share.

Operational Goal Results:

Gulf Power

Goal	Achievement Percentage
Customer Satisfaction	133
Reliability	117
Availability	139
Safety	0
Culture	121

Southern Company Generation

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	179
Availability	197
Safety	200
Culture	145

Alabama Power

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	170
Availability	200
Safety	200
Culture	132

Georgia Power

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	177
Availability	191
Safety	200
Culture	145

Overall, the levels of achievement shown above resulted in an operational goal performance factor for Gulf Power, Southern Company Generation, Alabama Power, and Georgia Power of 104%, 184%, 183%, and 185%, respectively.

Financial Goal Results:

Goal	Result	Achievement Percentage
Southern Company EPS, excluding impact of MCAR settlement tax deduction	$2.369	155
Gulf Power ROE	11.69%	88
Alabama Power ROE	13.31%	178
Georgia Power ROE	11.42%	73
Aggregate ROE	12.09%	111
Southern Power net income	$130 million	75

The aggregate ROE and Southern Power net income achievement resulted in a business unit financial achievement percentage for Southern Company Generation of 107%.

A total performance factor is determined by adding the results of Southern Company EPS, applicable business unit financial performance, and applicable operational goal performance and dividing by three. The total performance factor is multiplied by the target Performance Pay Program opportunity, described above, to determine the payout for each named executive officer. The table below shows the pay opportunity at target-level performance (as prorated per the description above for those that served in more than one position during the year) and the actual payout based on the actual performance shown above.

	Target Annual Performance Pay Program Opportunity ($)	Total Performance Factor (%)	Actual Annual Performance Pay Program Payout ($)
S. N. Story	256,434	116	297,463
R. S. Teel	92,669	132	122,771
P. C. Raymond	121,361	140	169,905
M. L. Burroughs	64,914	134	86,925
P. B. Jacob	110,677	116	128,385
T. J. McCullough	89,810	148	132,567
B. C. Terry	109,786	116	127,352

Long-Term Performance-Based Compensation

Long-term performance-based awards are intended to promote long-term success and increase Southern Company's stockholder value by directly tying a substantial portion of the named executive officers' total compensation to the interests of Southern Company's stockholders. The long-term awards provide an incentive to grow Southern Company's stockholder value.

For 2010, the Compensation Committee also made changes to the long-term performance-based compensation program. As described in the Market Data section above, the Compensation Committee establishes a target long-term performance-based compensation value for each named executive officer. Prior to 2010, the long-term program consisted of two components, stock options and performance dividends. In 2009, the value of stock options granted represented approximately 35% of the total long-term target value and performance dividends represented approximately 65%. For 2010, the Compensation Committee terminated the Performance Dividend Program. The transition out of the outstanding performance dividend awards is described below in the Performance Dividends section.

In 2010, the Compensation Committee granted stock options and performance shares. The Compensation Committee made the changes to the long-term performance-based compensation program because the prior practice of granting stock options with associated performance dividends was not a prevalent practice. Also, because the two components worked in tandem (performance dividends are only paid on options outstanding at the end of the performance period), it was difficult for the Compensation Committee to manage or adjust the mix of stock-price-based compensation (stock options) and relative peer-based compensation (performance dividends). Because stock options and performance shares are valued separately and the value of performance shares is not affected by the exercise of stock options, the Compensation Committee has more flexibility in adjusting the weight of the long-term components granted, including the ability to introduce additional long-term performance metrics. And, finally, because performance dividends were more difficult for employees to value, the Compensation Committee believes that performance shares will provide more incentive value.

Performance dividends are based on a four-year performance-measurement period and performance shares on a three-year period. The Compensation Committee made this change in performance period due to market prevalence. Four-year periods are much less prevalent than three-year performance periods. The Compensation Committee believes that three-year performance awards in combination with 10-year stock option terms provide an appropriate balance for motivating and incenting long-term performance. Because long-term awards are granted annually, changing the long-term performance period from four to three years does not result in additional target compensation.

Additionally, the Compensation Committee scaled back the number of participants in the long-term program from approximately 250 Gulf Power employees in 2009 to approximately 110 in 2010. The annual performance-based compensation target was increased appropriately for the affected employees to maintain the market competitiveness of these positions.

Southern Company stock options represent 40% of the long-term performance target value and performance shares represent the remaining 60%. The Compensation Committee elected this mix because it concluded that doing so represented an appropriate balance between incentives. Stock options only generate value if the value of the stock appreciates after the grant date and performance shares reward employees based on total shareholder return relative to peers.

The following table shows the grant date fair value of the long-term performance-based awards in total and each component awarded in 2010.

	Value of Options ($)	**Value of Performance Shares ($)**	**Total Long-Term Value ($)**
S. N. Story	176,335	264,481	440,816
R. S. Teel	31,508	47,244	78,752
P. C. Raymond	56,742	85,087	141,829
M. L. Burroughs	8,073	12,082	20,155
P. B. Jacob	57,217	85,810	143,027
T. J. McCullough	30,152	45,225	75,377
B. C. Terry	56,742	85,087	141,829

Stock Options

The stock options have a 10-year term, vest over a three-year period, fully vest upon retirement or termination of employment following a change in control, and expire at the earlier of five years from the date of retirement or the end of the 10-year term. The Compensation Committee changed the stock option vesting provisions associated with retirement for stock options granted in 2009 to the executive officers of Southern Company, including Ms. Story. For the grant to Ms. Story made in 2010, unvested options are forfeited if she retires and accepts a position with a peer company within two years of retirement. The Compensation Committee made this change to provide more retention value to the stock option awards, to provide an inducement to not seek a position with a peer company and to limit the post-termination compensation of any Southern Company executive officer who accepts a position with a peer company. The other named executive officers of Gulf Power were not affected by these changes. The value of each stock option was derived using the Black-Scholes stock option pricing model. The assumptions used in calculating that amount are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein. For 2010, the Black-Scholes value on the grant date was $2.23 per stock option.

Performance Shares

Performance shares are denominated in units, meaning no actual shares are issued at the grant date. A grant date fair value per unit was determined. For the grant made in 2010, that value per unit was $30.13. See the Summary Compensation Table and information accompanying it for more information on the grant date fair value. The total target value for performance share units is divided by the value per unit to determine the number of performance share units granted to each participant, including the named executive officers. Each performance share unit represents one share of Common Stock. At the end of the three-year performance-measurement period, the number of units will be adjusted up or down (zero to 200%) based on Southern Company's total shareholder return relative to that of its peers in the Philadelphia Utility Index and the custom peer group. The companies in the custom peer group are those that we believe are most similar to us in both business model and investors. The Philadelphia Utility Index was chosen because it is a published index and, because it includes a larger number of peer companies, it can mitigate volatility in results over time, providing an appropriate level of balance. The peer groups vary from the Market Data peer group (as listed on page III-9) due to the timing and criteria of the peer selection process. But, there is significant overlap. The results of the two peer groups will be averaged. The number of performance share units earned will be paid in Common Stock. No dividends or dividend equivalents will be paid or earned on the performance share units.

The companies in the Philadelphia Utility Index are listed below.

Ameren Corporation	Exelon Corporation
American Electric Power Company, Inc.	FirstEnergy Corp.
CenterPoint Energy, Inc.	NextEra Energy, Inc.
Consolidated Edison, Inc.	Northeast Utilities
Constellation Energy Group, Inc.	PG&E Corporation
Dominion Resources Inc.	Progress Energy, Inc.
DTE Energy Company	Public Service Enterprise Group Inc.
Duke Energy Corporation	The AES Corporation
Edison International	Xcel Energy Inc.
Entergy Corporation	

The companies in the custom peer group are listed below.

American Electric Power Company, Inc.	PG&E Corporation
Consolidated Edison, Inc.	Progress Energy, Inc.
Duke Energy Corporation	Wisconsin Energy Corporation
Northeast Utilities	Xcel Energy Inc.
NSTAR	

The scale below will determine the number of units paid in Common Stock following the last year of the performance-measurement period, based on the 2010-2012 performance-measurement period. Payout for performance between points will be interpolated on a straight-line basis.

Performance vs. Peer Groups	**Payout (% of Each Performance Share Unit Paid)**
90th percentile or higher (Maximum)	200
50th percentile (Target)	100
10th percentile (Threshold)	0

Performance shares are not earned until the end of the three-year performance period. A participant, who terminates, other than due to retirement or death, forfeits all unearned performance shares. Participants who retire or die during the performance period only earn a prorated number of units, based on the number of months they were employed during the performance period.

More information about the stock options and performance shares is contained in the Grants of Plan-Based Awards table and the information accompanying it.

Performance Dividends

As referenced above, the Compensation Committee terminated the Performance Dividend Program in 2010. The value of performance dividends represented a significant portion of long-term performance-based compensation that was awarded in 2007, 2008, and 2009. At target performance levels, performance dividends represented up to 65% of the total long-term value granted over the 10-year term of stock options. Therefore, because performance dividends were awarded for years prior to 2010, in fairness to participants, the outstanding performance dividend awards were not cancelled. The grant of performance shares, described above, replaced performance dividend awards beginning in 2010. Therefore, performance dividends will continue to be paid on stock options granted prior to 2010 that are outstanding at the end of the three remaining uncompleted four-year performance-measurement periods: 2007 - 2010, 2008 - 2011, and 2009 - 2012. Performance dividends granted prior to 2007 were paid on all stock options held at the end of the applicable performance period. Therefore, absent the exercise of stock options, the number of stock options upon which performance dividends were paid increased over the four-year performance-measurement period due to annual stock option grants. Under the transition period, the outstanding performance dividends will be paid only on stock options granted prior to 2010, when the first performance shares were granted. Because performance shares are earned at the end of a three-year performance measurement period, the last award of performance dividends and the first award of performance shares will be earned at the end of 2012.

Performance dividends can range from 0% to 100% of the Common Stock dividend paid during the year per eligible stock option held at the end of the performance-measurement period. Actual payout will depend on Southern Company's total shareholder return over a four-year performance-measurement period compared to a group of other electric and gas utility companies. The peer group was determined at the beginning of each four-year performance-measurement period. The peer group for performance dividends was set by the Compensation Committee at the beginning of the four-year performance-measurement period.

Total shareholder return is calculated by measuring the ending value of a hypothetical $100 invested in each company's common stock at the beginning of each of 16 quarters. In the final year of the performance-measurement period, Southern Company's ranking in the peer group is determined at the end of each quarter and the percentile ranking is multiplied by the actual Common Stock dividend paid in that quarter. To determine the total payout per stock option held at the end of the performance-measurement period, the four quarterly amounts earned are added together.

No performance dividends are paid if Southern Company's earnings are not sufficient to fund a Common Stock dividend at least equal to that paid in the prior year.

2010 Payout

The peer group used to determine the 2010 payout for the 2007-2010 performance-measurement period consisted of utilities with revenues of $1.2 billion or more with regulated revenues of 60% or more. Those companies are listed below.

Allegheny Energy, Inc.	Edison International	Progress Energy, Inc.
Alliant Energy Corporation	Entergy Corporation	SCANA Corporation
Ameren Corporation	Exelon Corporation	Sempra Energy
American Electric Power Company, Inc.	Hawaiian Electric	Sierra Pacific Resources
Avista	NextEra Energy, Inc.	TECO Energy
CenterPoint Energy, Inc.	NiSource, Inc.	UIL Holdings
CMS Energy Corporation	Northeast Utilities	Unisource
Consolidated Edison, Inc.	NSTAR	Vectren Corp.
DPL, Inc.	Pepco Holdings, Inc.	Westar Energy Corporation
DTE, Inc.	PG&E Corporation	Wisconsin Energy Corporation
Duke Energy Corporation	Pinnacle West Capital Corp.	Xcel Energy, Inc.

The scale below determined the percentage of each quarter's dividend paid in the last year of the performance-measurement period to be paid on each eligible stock option held at December 31, 2010, based on performance during the 2007-2010 performance-measurement period. Payout for performance between points was interpolated on a straight-line basis.

Performance vs. Peer Group	**Payout (% of Each Quarterly Dividend Paid)**
90th percentile or higher	100
50th percentile (Target)	50
10th percentile or lower	0

Southern Company's total shareholder return performance, as measured at the end of each quarter of the final year of the four-year performance-measurement period ending with 2010, was the 36th, 64th, 56th, and 56th percentile, respectively, resulting in a total payout of 106% of the target level (53% of the full year's Common Stock dividend), or $0.96. This amount was multiplied by each named executive officer's eligible outstanding stock options as of December 31, 2010, to calculate the payout under the program. The amount paid is included in the Non-Equity Incentive Plan Compensation column in the Summary Compensation Table.

Timing of Performance-Based Compensation

As discussed above, the 2010 annual Performance Pay Program goals and the Southern Company total shareholder return goals applicable to performance shares were established at the February 2010 Compensation Committee meeting. Annual stock option grants also were made at that meeting. The establishment of performance-based compensation goals and the granting of stock options were not timed with the release of material, non-public information. This procedure is consistent with prior practices. Stock option grants are made to new hires or newly-eligible participants on preset, regular quarterly dates that were approved by the Compensation Committee. The exercise price of options granted to employees in 2010 was the closing price of the Common Stock on the grant date or the last trading day before the grant date, if the grant date was not a trading day.

Retirement and Severance Benefits

As mentioned above, we provide certain post-employment compensation to employees, including the named executive officers.

Retirement Benefits

Generally, all full-time employees of Gulf Power participate in our funded Pension Plan after completing one year of service. Normal retirement benefits become payable when participants attain both age 65 and complete five years of participation. We also provide unfunded benefits that count salary and annual Performance Pay Program payouts that are ineligible to be counted under the Pension Plan. (These plans are the Supplemental Benefit Plan and the Supplemental Executive Retirement Plan that are described in the chart on page III-7 of this CD&A.) See the Pension Benefits table and the information accompanying it for more information about pension-related benefits.

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers. Gulf Power has a supplemental retirement agreement (SRA) with both Ms. Terry and Mr. Raymond. Prior to her employment, Ms. Terry provided legal services to Southern Company's subsidiaries. Mr. Raymond provided audit services through his prior employment with Southern Company's independent accounting firm. Ms. Terry's agreement provides retirement benefits as if she was employed an additional 10 years and Mr. Raymond's provides an additional 8 years of benefits. Ms. Terry and Mr. Raymond must remain employed at Gulf Power or an affiliate of Gulf Power for 10 and five years, respectively, before vesting in the benefits. These agreements provide a benefit which recognizes the expertise both brought to Gulf Power and they provide a strong retention incentive to remain with Gulf Power, or one of its affiliates, for the vesting period or longer.

Gulf Power also provides the Deferred Compensation Plan which is an unfunded plan that permits participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, disability, death, or other separation from service. Up to 50% of base salary and up to 100% of performance-based compensation, except stock options and performance shares, may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the Deferred Compensation Plan. See the Nonqualified Deferred Compensation table and the information accompanying it for more information about the Deferred Compensation Plan.

Change-in-Control Protections

The Compensation Committee initially approved the change-in-control protection program in 1998 to provide certain compensatory protections to employees, including the named executive officers, upon a change in control and thereby allow them to negotiate aggressively with a prospective purchaser. For all participants, payment and vesting would occur only upon the occurrence of both an actual change in control and loss of the individual's position. For the executive officers of Gulf Power, including the named executive officers, the level of severance benefits provided was two or three times salary plus target-level Performance Pay Program opportunity. These levels of benefits were consistent with that provided by other companies of our size and in our industry

Change-in-control protections, including severance pay and, in some situations, vesting or payment of long-term performance-based awards, are provided upon a change in control of the Southern Company or Gulf Power coupled with an involuntary termination not for cause or a voluntary termination for "Good Reason." This means there is a "double trigger" before severance benefits are paid; *i.e.,* there must be both a change in control and a termination of employment.

In early 2011, the Compensation Committee made changes to the program that were effective immediately. Notably, the following changes were made:

- Reduction of severance payment level from three times base salary plus target Performance Pay Program opportunity to two times that amount for all executive officers of Southern Company, including Ms. Story, except for the Chief Executive Officer of Southern Company. (In 2009, the Compensation Committee lowered the severance payment level for all other officers from two times base salary plus target Performance Pay Program opportunity to one times that amount.)

- Elimination of excise tax gross-up for all participants, including all named executive officers.

After the changes made in 2009 and 2011, Ms. Story's severance level is two times salary plus target Performance Pay Program opportunity and it is one times that amount for all other named executive officers of Gulf Power.

More information about severance arrangements is included in the section entitled Potential Payments upon Termination or Change in Control.

Perquisites
Gulf Power provides limited perquisites to its executive officers, including the named executive officers. The perquisites provided in 2010, including amounts, are described in detail in the information accompanying the Summary Compensation Table. In 2009, the Compensation Committee eliminated tax assistance (tax gross-up) on all perquisites for executive officers of Southern Company, including Ms. Story, except on relocation-related benefits. Effective November 1, 2010, the Compensation Committee eliminated Gulf Power-provided home security monitoring and reimbursement of country club dues. A one-time salary increase equal to the annual dues amount was provided. This change was applicable to all employees of Gulf Power with company-paid memberships. Reimbursement of country club initiation fees will continue if it is determined that there is an established business need for the membership.

Southern Company is recognized externally for its depth of management succession bench strength. This is consistently validated by the continued strong performance of Southern Company during times of leadership transition. A significant contributor to this is Southern Company's long-standing practice of developing its leaders, as well as its technical, professional, and management talent, internally. Our internal talent development efforts allow us to promote from within rather than relying on external executive hiring. An important component of our program is to provide multiple company experience. In 2010, over 400 employees relocated at the request of Southern Company, including four named executive officers of Gulf Power. Mr. Raymond became Vice President and Chief Financial Officer of Alabama Power and relocated to Birmingham, Alabama. He was replaced by Mr. Teel who relocated to Pensacola, Florida from Birmingham, Alabama. Mr. McCullough was named Vice President of Alabama Power and relocated to Birmingham, Alabama. He was replaced by Mr. Burroughs who relocated from Newnan, Georgia to Pensacola, Florida.

We believe that it is important, to the extent possible, to keep employees whole, financially, when they relocate at our request. We regularly review market practices on the level of relocation benefits provided to employees. The review we conducted in 2010 showed that reimbursing employees for loss on home sale, and providing tax assistance on all relocation benefits, are still majority practices. Under our relocation policy, employees were reimbursed for up to 10% of their home's original purchase price if it sold or appraised for less than the original purchase price. However, due to the unprecedented downturn in the housing market, many employees were experiencing greater losses. To address this concern, and based on our review of the level of relocation benefits provided by other companies, we modified the home loss benefit in 2010, retroactive to January 1, 2009, to reimburse employees for their full loss on sale and for capital improvements made within the last five years. We also committed to review these policy changes at least annually and will reconsider the level of benefits provided as the housing market recovers. As with other relocation-related benefits, tax assistance is provided on the home loss and capital improvements reimbursement.

The Compensation Committee approved application of the modifications to Southern Company's executive officers, including Ms. Story, who relocated in 2010. However, the Compensation Committee also stipulated that any amount paid to a Southern Company executive officer for home loss, including tax assistance, must be reimbursed if he or she voluntarily terminates, or is involuntarily terminated for cause, less than two years following relocation. Future executive relocations will be reviewed by the Compensation Committee on a case-by-case basis to determine if reimbursement for home loss and tax assistance are warranted based on market practices and economic conditions. Ms. Story was reimbursed for her home loss and capital improvements on her home in Pensacola, Florida and tax assistance was provided. All relocation benefits provided to Gulf Power's named executive officers, including amounts, are described in the information accompanying the Summary Compensation Table.

Executive Stock Ownership Requirements
Effective January 1, 2006, the Compensation Committee adopted Common Stock ownership requirements for officers of Southern Company and its subsidiaries that are in a position of vice president or above. All of Gulf Power's named executive officers are covered by the requirements. The guidelines were implemented to further

align the interest of officers and Southern Company's stockholders by promoting a long-term focus and long-term share ownership.

The types of ownership arrangements counted toward the requirements are shares owned outright, those held in Southern Company-sponsored plans, and Common Stock accounts in the Deferred Compensation Plan and the Supplemental Benefit Plan. One-third of vested Southern Company stock options may be counted, but, if so, the ownership requirement is doubled. The ownership requirement is reduced by one-half at age 60.

The requirements are expressed as a multiple of base salary per the table below.

	Multiple of Salary without Counting Stock Options	**Multiple of Salary Counting 1/3 of Vested Options**
S. N. Story	3 Times	6 Times
R. S. Teel	2 Times	4 Times
P. C. Raymond	2 Times	4 Times
M. L. Burroughs	1 Times	2 Times
P. B. Jacob	2 Times	4 Times
T. J. McCullough	2 Times	4 Times
B. C. Terry	2 Times	4 Times

Officers serving as of January 1, 2006 have until September 30, 2011 to meet the applicable ownership requirement. Newly-elected officers have five years from the date of their election to meet the applicable ownership requirement and newly-promoted officers have five years from the date of their promotion to meet increased ownership requirements.

Policy on Recovery of Awards

Southern Company's Omnibus Incentive Compensation Plan provides that, if Southern Company or Gulf Power is required to prepare an accounting restatement due to material noncompliance as a result of misconduct, and if an executive officer knowingly or grossly negligently engaged in or failed to prevent the misconduct or is subject to automatic forfeiture under the Sarbanes-Oxley Act of 2002, the executive officer will reimburse the amount of any payment in settlement of awards earned or accrued during the 12-month period following the first public issuance or filing that was restated.

Company Policy Regarding Hedging the Economic Risk of Stock Ownership

Southern Company's policy is that employees and outside directors will not trade Southern Company options on the options market and will not engage in short sales.

COMPENSATION COMMITTEE REPORT

The Compensation Committee met with management to review and discuss the CD&A. Based on such review and discussion, the Compensation Committee recommended to the Southern Company Board of Directors that the CD&A be included in Gulf Power's Annual Report on Form 10-K for the fiscal year ended December 31, 2010. The Southern Company Board of Directors approved that recommendation.

Members of the Compensation Committee:

J. Neal Purcell, Chair
Henry A. Clark, III
H. William Habermeyer, Jr.
Donald M. James

SUMMARY COMPENSATION TABLE

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation ($) (i)	Total ($) (j)
S. N. Story	2010	420,643	0	264,481	176,335	553,744	481,895	705,506	2,602,604
President, Chief	2009	411,318	0	0	180,401	455,257	403,615	41,374	1,491,965
Executive Officer,	2008	390,602	0	0	102,872	509,067	128,423	39,109	1,170,073
and Director									
P. C. Raymond	2010	245,106	25,771	85,087	56,742	235,693	422,630	306,927	1,377,956
Vice President and	2009	237,219	0	0	49,939	146,636	147,437	180,666	761,897
Chief Financial	2008	215,880	23,731	0	21,283	181,206	48,120	44,446	534,666
Officer									
R. S. Teel	2010	205,540	22,056	47,244	31,508	171,316	50,082	448,620	976,366
Vice President and Chief Financial Officer									
M. L. Burroughs	2010	150,745	24,612	12,082	8,073	95,255	94,324	220,820	605,911
Vice President									
P. B. Jacob	2010	239,444	0	85,810	57,217	172,892	176,201	19,021	750,585
Vice President	2009	239,205	0	0	50,359	146,661	199,239	23,487	658,951
	2008	227,419	0	0	32,670	181,151	103,293	22,219	566,752
T. J.	2010	201,212	20,965	45,225	30,152	170,595	112,416	319,261	899,826
McCullough	2009	190,010	0	0	26,667	105,148	111,520	17,805	451,150
Vice President	2008	180,717	0	0	20,790	139,937	30,798	78,720	450,962
B. C. Terry	2010	237,466	0	85,087	56,742	183,929	259,023	22,542	844,789
Vice President	2009	237,219	0	0	49,939	134,728	48,437	25,427	495,750
	2008	222,172	5,150	0	30,616	166,985	13,845	26,250	465,018

Column (a)

Mr. Raymond was an executive officer of Gulf Power until August 12, 2010 and was succeeded by Mr. Teel. Mr. McCullough was an executive officer of Gulf Power until June 29, 2010 and was succeeded by Mr. Burroughs. Messrs. Burroughs and Teel were not executive officers prior to 2010.

Column (d)

The amounts shown for 2010 are geographic relocation incentives that were paid in connection with relocation of the applicable named executive officers. The relocation incentive equaled 10% of salary rate as of the date of relocation. Mr. Burroughs also received a bonus of $7,120 for his outstanding performance during the Southern Company Generation leadership transition at Gulf Power.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2010. Rather, as required by applicable rules of the Securities and Exchange Commission (SEC), this column reports the aggregate grant date fair value of performance shares granted in 2010. The value reported is based on the probable outcome of the performance conditions as of the grant date, using a Monte Carlo simulation model. No amounts will be earned until the end of the three-year performance period on December 31, 2012. The value then can be earned based on performance ranging from 0 to 200% as established by the Compensation Committee. The aggregate grant date fair value of the performance shares granted in 2010 to Messes. Story and Terry and Messrs. Raymond, Teel, Burroughs, Jacob, and McCullough, assuming the highest level of performance is achieved, is $528,962, $170,174, $170,174, $94,488, $24,164, $171,620, and $90,450, respectively (200% of the amount show in the table). See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

As described in detail in the CD&A, in 2010 the first awards of performance shares were made and no further awards of performance dividends were made. In 2008 and 2009, stock options were awarded (as shown in column (f)) with associated performance dividends, as described in the CD&A. The grant date value of performance dividends was reported in the CD&A and the threshold, target, and maximum payouts of performance dividends based on certain assumptions were reported in the Grants of Plan-Based Awards table. However, because of disclosure requirements, no grant date value for performance dividend awards was disclosed in the Summary Compensation Table in the year granted. Instead, the actual cash payouts in the applicable year with respect to all outstanding performance dividends were reported as Non-Equity Incentive Plan Compensation in column (g). The grant date value for performance dividends as reported in the CD&A for 2008 and 2009 is as follows:

	2008	**2009**
S. N. Story	156,696	314,700
P. C. Raymond	32,418	87,116
R. S. Teel	32,772	48,142
M. L. Burroughs	9,422	12,114
P. B. Jacob	49,764	87,848
T. J. McCullough	31,667	46,519
B. C. Terry	46,634	87,116

Column (f)

This column reports the aggregate grant date fair value of stock options. See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (g)

The amounts in this column are the aggregate of the payouts under the annual Performance Pay Program and under the Performance Dividend Program. The amount reported for annual performance-based compensation is for the one-year performance period ended December 31, 2010. The amount reported for performance dividends is the amount earned at the end of the four-year performance-measurement period of January 1, 2007 through December 31, 2010. These awards were granted by the Compensation Committee in 2007 and are paid on stock options granted prior to 2010 that were outstanding at the end of 2010. As described in the CD&A, the Performance Dividend Program was eliminated by the Compensation Committee in 2010 and replaced with performance shares. This payout reported in column (g) is the first payout in the three-year transition period as described in the CD&A for the open four-year performance-measurement periods (2007-2010, 2008-2011, and 2009-2012) that were granted by the Compensation Committee in 2007, 2008, and 2009, respectively. The Performance Pay Program, the Performance Dividend Program, and performance shares are described in detail in the CD&A.

The amounts paid under each program to the named executive officers are shown below.

	Annual Performance-Based Compensation ($)	**Performance Dividends ($)**	**Total ($)**
S. N. Story	297,463	256,281	553,744
P. C. Raymond	169,905	65,788	235,693
R. S. Teel	122,771	48,545	171,316
M. L. Burroughs	86,925	8,330	95,255
P. B. Jacob	128,385	44,507	172,892
T. J. McCullough	132,567	38,028	170,595
B. C. Terry	127,352	56,577	183,929

Column (h)

This column reports the aggregate change in the actuarial present value of each named executive officer's accumulated benefit under the Pension Plan and the supplemental pension plans (collectively, Pension Benefits) during 2008, 2009, and 2010. The amount included for 2008 is the difference between the actuarial present values of the Pension Benefits measured as of September 30, 2007 and December 31, 2008 – 15 months rather than one year. September 30 was used as the measurement date prior to 2008, because it was the date as of which Southern Company measured its retirement benefit obligations for accounting purposes. Starting in 2008, Southern Company changed its measurement date to December 31. The amounts for 2009 and 2010 are the differences between the actuarial values of the Pension Benefits measured as of December 31, 2008 and 2009, and December 31, 2009 and 2010, respectively. The Pension Benefits as of each measurement date are based on the named executive officer's age, pay, and service accruals and the plan provisions applicable as of the measurement date. The actuarial present values as of each measurement date reflect the assumptions Gulf Power selected for cost purposes as of that measurement date; however, the named executive officers were assumed to remain employed at Gulf Power or any other Southern Company subsidiary until their benefits commence at the pension plans' stated normal retirement date, generally age 65. As a result, the amounts in column (h) related to Pension Benefits represent the combined impact of several factors: growth in the named executive officer's Pension Benefits over the measurement year; impact on the total present values of one year shorter discounting period due to the named executive officer being one year closer to normal retirement; impact on the total present values attributable to changes in assumptions from measurement date to measurement date; and impact on the total present values attributable to plan changes between measurement dates.

For more information about the Pension Benefits and the assumptions used to calculate the actuarial present value of accumulated benefits as of December 31, 2010, see the information following the Pension Benefits table. The key differences between assumptions used for the actuarial present values of accumulated benefits calculations as of December 31, 2009 and December 31, 2010 follow:

- Discount rate for the Pension Plan was decreased to 5.55% as of December 31, 2010 from 5.95% as of December 31, 2009
- Discount rate for the supplemental pension plans was decreased to 5.05% as of December 31, 2010 from 5.60% as of December 31, 2009

This column also reports above-market earnings on deferred compensation under the Deferred Compensation Plan (DCP). However, there were no above-market earnings on deferred compensation in 2010, 2009, or 2008.

Column (i)

This column reports the following items: perquisites; tax reimbursements by the employing company on certain perquisites; the employing company's contributions in 2010 to the Southern Company Employee Savings Plan (ESP), which is a tax-qualified defined contribution plan intended to meet requirements of Section 401(k) of the Code; and the employing company's contributions in 2010 under the Southern Company Supplemental Benefit Plan (Non-Pension Related) (SBP). The SBP is described more fully in the information following the Nonqualified Deferred Compensation table.

The amounts reported are itemized below.

Name	Perquisites ($)	Tax Reimbursements ($)	ESP ($)	SBP ($)	Total ($)
S. N. Story	478,186	205,867	12,495	8,958	705,506
P. C. Raymond	201,994	92,983	11,945	5	306,927
R. S. Teel	300,241	137,896	10,483	0	448,620
M. L. Burroughs	164,520	48,612	7,688	0	220,820
P. B. Jacob	7,898	525	10,598	0	19,021
T. J. McCullough	231,534	77,465	10,262	0	319,261
B. C. Terry	11,094	822	10,626	0	22,542

Description of Perquisites

Personal Financial Planning is provided for most officers of Gulf Power, including all of the named executive officers. Gulf Power pays for the services of the financial planner on behalf of the officers, up to a maximum amount of $8,700 per year, after the initial year that the benefit is provided. In the initial year, the allowed amount is $15,000. The employing company also provides a five-year allowance of $6,000 for estate planning and tax return preparation fees.

Personal Use of Company-Provided Club Memberships. The employing company provided club memberships to certain officers, including most of the named executive officers. The memberships were provided for business use; however, personal use was permitted. The amount included reflects the pro-rata portion of the membership fees paid by the employing company that are attributable to the named executive officers' personal use. Direct costs associated with any personal use, such as meals, are paid for or reimbursed by the employee and therefore are not included. As described in the CD&A, this perquisite was eliminated in 2010.

Relocation Benefits. These benefits are provided to cover the costs associated with geographic relocation. As described in the CD&A, Ms. Story and Messrs. Raymond, Teel, Burroughs, and McCullough relocated during 2010 and received relocation-related benefits in the amount of $471,133, $194,834, $299,109, $164,254, and $224,723, respectively. Relocation assistance includes the incremental cost paid or incurred by Gulf Power or its affiliates for relocation, including loss on sale and certain capital improvements, of residence in former location, home sale and home repurchase assistance (closing costs), shipment of household goods, temporary housing costs during the move, and in some cases a lump sum relocation allowance. Under the relocation policy applicable to all employees, as described in detail in the CD&A, any loss on home sale is determined based on the purchase price paid for the residence plus the cost of capital improvements made within the last five years to the residence that qualify for addition to the tax basis of the residence. Also, as provided in the policy, tax assistance was provided on the taxable relocation benefits, including the reimbursement for loss on home sale. For Ms. Story, if she terminates within two years of her relocation, the amount provided for loss on home sale, including tax assistance, must be repaid.

Personal Use of Corporate-Owned Aircraft. Southern Company owns aircraft that are used to facilitate business travel. If seating is available, Southern Company permits a spouse or other family member to accompany an employee on a flight. However, because in such cases the aircraft is being used for a business purpose, there is no incremental cost associated with the family travel and no amounts are included for such travel. Any additional expenses incurred that are related to family travel are included.

Home Security Systems. Gulf Power paid for the services of third-party providers for the installation, maintenance, and monitoring of the named executive officers' home security systems. As reported in the CD&A, this perquisite was eliminated during 2010.

Other Miscellaneous Perquisites. The amount included reflects the full cost to Gulf Power of providing the following items: personal use of company provided tickets for sporting and other entertainment events and gifts distributed to and activities provided to attendees at company-sponsored events.

For Ms. Story, effective in 2009, tax reimbursements are no longer made on perquisites, except on relocation benefits.

GRANTS OF PLAN-BASED AWARDS IN 2010

This table provides information on stock option grants made and goals established for future payouts under the performance-based compensation programs during 2010 by the Compensation Committee.

		Estimated Possible Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards					
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Option Awards: Number of Securities Underlying Options (#) (i)	Exercise or Base Price of Option Awards ($/Sh) (j)	Grant Date Fair Value of Stock and Option Awards ($) (k)
S. N. Story	2/15/2010	2,564	256,434	512,867						
	2/15/2010				88	8,778	17,556			264,481
	2/15/2010							79,074	31.17	176,335
P. C. Raymond	2/15/2010	1,214	121,361	242,722						
	2/15/2010				28	2,824	5,648			85,087
	2/15/2010							25,445	31.17	56,742
R. S. Teel	2/15/2010	927	92,669	185,338						
	2/15/2010				16	1,568	3,136			47,244
	2/15/2010							14,129	31.17	31,508
M. L. Burroughs	2/15/2010	649	64,915	129,829						
	2/15/2010				4	401	802			12,082
	2/15/2010							3,620	31.17	8,073
P. B. Jacob	2/15/2010	1,107	110,677	221,354						
	2/15/2010				28	2,848	5,696			85,810
	2/15/2010							25,658	31.17	57,217
T. J. McCullough	2/15/2010	898	89,810	179,619						
	2/15/2010				15	1,501	3,002			45,225
	2/15/2010							13,521	31.17	30,152
B. C. Terry	2/15/2010	1,098	109,786	219,573						
	2/15/2010				28	2,824	5,648			85,087
	2/15/2010							25,445	31.17	56,742

Columns (c), (d), and (e)

Reflects the annual Performance Pay Program opportunity granted to the named executive officers in 2010 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. The actual amounts earned are disclosed in the Summary Compensation Table.

Columns (f), (g), and (h)

Reflects the performance shares granted to the named executive officers in 2010 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. Earned performance shares will be paid out in Common Stock following the end of the 2010-2012 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

Columns (i) and (j)

Column (i) reflects the number of stock options granted to the named executive officers in 2010, as described in the CD&A, and column (j) the exercise price of the stock options. The Compensation Committee granted these stock options at its regularly-scheduled meeting on February 15, 2010 which was a holiday. Under the terms of the

Omnibus Incentive Compensation Plan, the exercise price was set at the closing price on February 12, 2010, which was the last trading day prior to the grant date.

Column (k)

Reflects the aggregate grant date fair value of the performance shares and stock options granted in 2010. For performance shares, the value is based on the probable outcome of the performance conditions as of the grant date using a Monte Carlo simulation model. For stock options, the value is derived using the Black-Scholes stock option pricing model. The assumptions used in calculating these amounts are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein.

OUTSTANDING EQUITY AWARDS AT 2010 FISCAL YEAR-END

This table provides information pertaining to all outstanding stock options and stock award (performance shares) held by or granted to the named executive officers as of December 31, 2010.

	Option Awards				Stock Awards	
Name (a)	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Option Exercise Price ($) (d	Option Expiration Date (e)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (f)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (g)
S. N. Story	38,529	0	32.70	02/18/2015		
	41,329		33.81	02/20/2016		
	43,472		36.42	02/19/2017		
	28,937	14,469	35.78	02/18/2018		
	33,408	66,815	31.39	02/16/2019		
	-	79,074	31.17	02/15/2020		
					88	3,364
P. C. Raymond	4,196	0	29.50	02/13/2014		
	9,463	0	32.70	02/18/2015		
	8,882	0	33.81	02/20/2016		
	9,264	0	36.42	02/19/2017		
	5,987	2,993	35.78	02/18/2018		
	9,248	18,496	31.39	02/16/2019		
	-	25,445	31.17	02/15/2020		
					28	1,070
R. S. Teel	5,572	0	29.50	02/13/2014		
	5,550		32.70	02/18/2015		
	5,771		33.81	02/20/2016		
	9,265		36.42	02/19/2017		
	6,052	3,026	35.78	02/18/2018		
	5,111	10,221	31.39	02/16/2019		
	–	14,129	31.17	02/15/2020		
					16	612
M. L. Burroughs	316		32.70	02/18/2015		
	289		33.81	02/20/2016		
	1,604		36.42	02/19/2017		
	1,740	870	35.78	02/18/2018		
	1,286	2,572	31.39	02/16/2019		
	–	3,620	31.17	02/15/2020		
					4	153
P. B. Jacob	13,925	0	36.42	02/19/2017		
	9,190	4,595	35.78	02/18/2018		
	0	18,651	31.39	02/16/2019		
	–	25,658	31.17	02/15/2020		
					28	1,070
T. J. McCullough	5,468	0	32.70	02/18/2015		
	5,108	0	33.81	02/20/2016		
	5,449	0	36.42	02/19/2017		
	5,848	2,924	35.78	02/18/2018		
	4,939	9,876	31.39	02/16/2019		
	–	13,521	31.17	02/15/2020		
					15	573
B. C. Terry	8,905	0	33.81	02/20/2016		
	9,367		36.42	02/19/2017		
	8,612	4,306	35.78	02/18/2018		
	9,248	18,496	31.39	02/16/2019		
	–	25,445	31.17	02/15/2020		
					28	1,070

Columns (b), (c), (d), and (e)

Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2004 through 2007 with expiration dates from 2014 through 2017 were fully vested as of December 31, 2010. The options granted in 2008, 2009, and 2010 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2008	February 18, 2018	February 18, 2011
2009	February 16, 2019	February 16, 2012
2010	February 15, 2020	February 15, 2013

Options also fully vest upon death, total disability, or retirement and expire three years following death or total disability or five years following retirement, or on the original expiration date if earlier. Please see Potential Payments upon Termination or Change in Control for more information about the treatment of stock options under different termination and change-in-control events.

Columns (f) and (g)

Reflects the threshold number of performance shares that can be earned at the end of the three-year performance period (December 31, 2012) that were granted in 2010, as reported in column (f) of the Grants of Plan-Based Awards table. The value in column (g) is derived by multiplying the number of shares in column (f) by the Common Stock closing price on December 31, 2010 ($38.23). See further discussion of performance shares in the CD&A.

OPTION EXERCISES AND STOCK VESTED IN 2010

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting (#) (d)	Value Realized on Vesting ($) (e)
S. N. Story	0	0	0	0
P. C. Raymond	1,230	12,075	0	0
R. S. Teel	0	0	0	0
M. L. Burroughs	5,077	46,589	0	0
P. B. Jacob	22,889	65,979	0	0
T. J. McCullough	7,406	56,560	0	0
B. C. Terry	0	0	0	0

Reflects the number of shares acquired upon the exercise of stock options during 2010 (column (b)) and the value realized (column (c)). The value realized is the difference in the market price over the exercise price on the exercise date.

No stock awards (performance shares) vested in 2010.

PENSION BENEFITS AT 2010 FISCAL YEAR-END

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
S. N. Story	Pension Plan	28.00	607,320	0
	SBP-P	28.00	901,302	0
	SERP	28.00	553,208	0
P. C. Raymond	Pension Plan	19.00	385,033	0
	SBP-P	19.00	70,555	0
	SERP	19.00	128,017	0
	SRA	8.00	291,036	0
R. S. Teel	Pension Plan	10.33	106,431	0
	SBP-P	10.33	18,021	0
	SERP	10.33	42,125	0
M. L. Burroughs	Pension Plan	2.00	285,396	0
	SBP-P	2.00	80,192	0
	SERP	2.00	86,423	0
P. B. Jacob	Pension Plan	27.42	733,143	0
	SBP-P	27.42	190,905	0
	SERP	27.42	203,968	0
T. J. McCullough	Pension Plan	22.75	310,853	0
	SBP-P	22.75	45,507	0
	SERP	22.75	108,137	0
B. C. Terry	Pension Plan	8.50	105,604	0
	SBP-P	8.50	14,692	0
	SERP	8.50	36,085	0
	SRA	10.00	215,195	0

Pension Plan
The Pension Plan is a tax-qualified, funded plan. It is Southern Company's primary retirement plan. Generally, all full-time employees participate in this plan after one year of service. Normal retirement benefits become payable when participants attain both age 65 and complete five years of participation. The plan benefit equals the greater of amounts computed using a "1.7% offset formula" and a "1.25% formula," as described below. Benefits are limited to a statutory maximum.

The 1.7% offset formula amount equals 1.7% of final average pay times years of participation less an offset related to Social Security benefits. The offset equals a service ratio times 50% of the anticipated Social Security benefits in excess of $4,200. The service ratio adjusts the offset for the portion of a full career that a participant has worked. The highest three rates of pay out of a participant's last 10 calendar years of service are averaged to derive final average pay. The pay considered for this formula is the base rate of pay reduced for any voluntary deferrals. A statutory limit restricts the amount considered each year; the limit for 2010 was $245,000.

The 1.25% formula amount equals 1.25% of final average pay times years of participation. For this formula, the final average pay computation is the same as above, but annual performance-based compensation paid during each year is added to the base rates of pay.

Early retirement benefits become payable once plan participants have during employment attained both age 50 and completed 10 years of participation. Participants who retire early from active service receive benefits equal to the amounts computed using the same formulas employed at normal retirement. However, a 0.3% reduction applies for each month (3.6% for each year) prior to normal retirement that participants elect to have their benefit payments commence. For example, 64% of the formula benefits are payable starting at age 55. As of December 31, 2010, Ms. Terry and Messrs. McCullough and Teel were not eligible to retire immediately.

The Pension Plan's benefit formulas produce amounts payable monthly over a participant's post-retirement lifetime. At retirement, plan participants can choose to receive their benefits in one of seven alternative forms of payment. All forms pay benefits monthly over the lifetime of the retiree or the joint lifetimes of the retiree and a spouse. A reduction applies if a retiring participant chooses a payment form other than a single life annuity. The reduction makes the value of the benefits paid in the form chosen comparable to what it would have been if benefits were paid as a single life annuity over the retiree's life.

Participants vest in the Pension Plan after completing five years of service. All the named executive officers are vested in their Pension Plan benefits. Participants who terminate employment after vesting can elect to have their pension benefits commence at age 50 if they participated in the Pension Plan for 10 years. If such an election is made, the early retirement reductions that apply are actuarially determined factors and are larger than 0.3% per month.

If a participant dies while actively employed, benefits will be paid to a surviving spouse. A survivor's benefit equals 45% of the monthly benefit that the participant had earned before his or her death. Payments to a surviving spouse of a participant who could have retired will begin immediately. Payments to a survivor of a participant who was not retirement-eligible will begin when the deceased participant would have attained age 50. After commencing, survivor benefits are payable monthly for the remainder of a survivor's life. Participants who are eligible for early retirement may opt to have an 80% survivor benefit paid if they die; however, there is a charge associated with this election.

If participants become totally disabled, periods that Social Security or employer-provided disability income benefits are paid will count as service for benefit calculation purposes. The crediting of this additional service ceases at the point a disabled participant elects to commence retirement payments. Outside of the extra service crediting, the normal plan provisions apply to disabled participants.

The Southern Company Supplemental Benefit Plan (Pension-Related) (SBP-P)
The SBP-P is an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees any benefits that the Pension Plan cannot pay due to statutory pay/benefit limits. The SBP-P's vesting, early retirement, and disability provisions mirror those of the Pension Plan.

The amounts paid by the SBP-P are based on the additional monthly benefit that the Pension Plan would pay if the statutory limits and pay deferrals were ignored. When an SBP-P participant separates from service, vested monthly benefits provided by the benefit formulas are converted into a single sum value. It equals the present value of what would have been paid monthly for an actuarially determined average post-retirement lifetime. The discount rate used in the calculation is based on the 30-year U.S. Treasury yields for the September preceding the calendar year of separation, but not more than six percent. Vested participants terminating prior to becoming eligible to retire will be paid their single sum value as of September 1 following the calendar year of separation. If the terminating participant is retirement eligible, the single sum value will be paid in 10 annual installments starting shortly after separation. The unpaid balance of a retiree's single sum will be credited with interest at the prime rate published in *The Wall Street Journal*. If the separating participant is a "key man" under Section 409A of the Code, the first installment will be delayed for six months after the date of separation.

If an SBP-P participant dies after becoming vested in the Pension Plan, the spouse of the deceased participant will receive the installments the participant would have been paid upon retirement. If a vested participant's death occurs prior to age 50, the installments will be paid to a spouse as if the participant had survived to age 50.

The Southern Company Supplemental Executive Retirement Plan (SERP)
The SERP also is an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees additional benefits that the Pension Plan and the SBP-P would pay if the 1.7% offset formula calculations reflected a portion of annual performance-based compensation. To derive the SERP benefits, a final average pay is determined reflecting participants' base rates of pay and their annual performance-based compensation amounts to the extent they exceed 15% of those base rates (ignoring statutory limits). This final average pay is used in the 1.7% offset formula to derive a gross benefit. The Pension Plan and the SBP-P benefits are subtracted from the gross benefit to calculate the SERP benefit. The SERP's early retirement, survivor benefit, and disability provisions mirror the SBP-P's provisions. However, except upon a change in control, SERP benefits do not vest until participants retire, so no

benefits are paid if a participant terminates prior to becoming retirement-eligible. More information about vesting and payment of SERP benefits following a change in control is included in the section entitled Potential Payments upon Termination or Change in Control.

SRA

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers and generally provide for additional retirement benefits by giving credit for years of employment prior to employment with Gulf Power or one of its affiliates. Information about the supplemental retirement agreements with Ms. Terry and Mr. Raymond is included in the CD&A.

The following assumptions were used in the present value calculations:

- Discount rate — 5.55% Pension Plan and 5.05% supplemental plans as of December 31, 2010
- Retirement date — Normal retirement age (65 for all named executive officers)
- Mortality after normal retirement — RP2000 Combined Healthy with generational projections
- Mortality, withdrawal, disability, and retirement rates prior to normal retirement — None
- Form of payment for Pension Benefits
  - Male retirees: 25% single life annuity; 25% level income annuity; 25% joint and 50% survivor annuity; and 25% joint and 100% survivor annuity
  - Female retirees: 40% single life annuity; 40% level income annuity; 10% joint and 50% survivor annuity; and 10% joint and 100% survivor annuity
- Spouse ages — Wives two years younger than their husbands
- Annual performance-based compensation earned but unpaid as of the measurement date — 130% of target opportunity percentages times base rate of pay for year amount is earned.
- Installment determination—4.25% discount rate for single sum calculation and 5.00% prime rate during installment payment period

For all of the named executive officers, the number of years of credited service is one year less than the number of years of employment.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2010 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
S. N. Story	0	8,958	112,329	0	1,717,374
P. C. Raymond	0	5	72	0	577
R. S. Teel	0	0	13	0	105
M. L. Burroughs	0	0	0	0	0
P. B. Jacob	76,175	0	34,048	0	244,903
T. J. McCullough	5,343	0	13,656	0	77,701
B. C. Terry	0	0	2,451	0	70,783

Southern Company provides the DCP which is designed to permit participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, or other separation from service. Up to 50% of base salary and up to 100% of performance-based compensation, except stock options, may be deferred, at the election of eligible employees. All of the named executive officers are eligible to participate in the DCP.

Participants have two options for the deemed investments of the amounts deferred — the Stock Equivalent Account and the Prime Equivalent Account. Under the terms of the DCP, participants are permitted to transfer between investments at any time.

The amounts deferred in the Stock Equivalent Account are treated as if invested at an equivalent rate of return to that of an actual investment in Common Stock, including the crediting of dividend equivalents as such are paid by Southern Company from time to time. It provides participants with an equivalent opportunity for the capital appreciation (or loss) and income of that of a Southern Company stockholder. During 2010, the rate of return in the Stock Equivalent Account was 20.8% which was Southern Company's total shareholder return for 2010.

Alternatively, participants may elect to have their deferred compensation deemed invested in the Prime Equivalent Account which is treated as if invested at a prime interest rate compounded monthly, as published in *The Wall Street Journal* as the base rate on corporate loans posted as of the last business day of each month by at least 75% of the United States' largest banks. The interest rate earned on amounts deferred during 2010 in the Prime Equivalent Account was 3.25%.

Column (b)

This column reports the actual amounts of compensation deferred under the DCP by each named executive officer in 2010. The amount of salary deferred by the named executive officers, if any, is included in the Salary column in the Summary Compensation Table. The amounts of performance-based compensation deferred in 2010 were the amounts paid for performance under the annual Performance Pay Program and the Performance Dividend Program that were earned as of December 31, 2009 but not payable until the first quarter of 2010. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2010, but not payable until early 2011. These deferred amounts may be distributed in a lump sum or in up to 10 annual installments at termination of employment or in a lump sum at a specified date, at the election of the participant.

Column (c)

This column reflects contributions under the SBP. Under the Code, employer matching contributions are prohibited under the ESP on employee contributions above stated limits in the ESP, and, if applicable, above legal limits set forth in the Code. The SBP is a nonqualified deferred compensation plan under which contributions are made that are prohibited from being made in the ESP. The contributions are treated as if invested in Common Stock and are payable in cash upon termination of employment in a lump sum or in up to 20 annual installments, at the election of the participant. The amounts reported in this column also were reported in the All Other Compensation column in the Summary Compensation Table.

Column (d)

This column reports earnings or losses on both compensation the named executive officers elected to defer and on employer contributions under the SBP.

Column (f)

This column includes amounts that were deferred under the DCP and contributions under the SBP in prior years and reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K. The chart below shows the amounts reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K.

	Amounts Deferred under the DCP Prior to 2010 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Employer Contributions under the SBP Prior to 2010 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Total ($)
S. N. Story	18,373	275,274	293,647
P. C. Raymond	0	0	0
R. S. Teel	0	0	0
M. L. Burroughs	0	0	0
P. B. Jacob	97,535	22,674	120,209
T. J. McCullough	28,460	0	28,460
B. C. Terry	121,427	0	121,427

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

This section describes and estimates payments that could be made to the named executive officers under different termination and change-in-control events. The estimated payments would be made under the terms of Southern Company's compensation and benefits programs or the change-in-control severance program. All of the named executive officers are participants in Southern Company's change-in-control severance plan for officers. The amount of potential payments is calculated as if the triggering events occurred as of December 31, 2010 and assumes that the price of Common Stock is the closing market price on December 31, 2010.

Description of Termination and Change-in-Control Events
The following charts list different types of termination and change-in-control events that can affect the treatment of payments under the compensation and benefit programs. These events also affect payments to the named executive officers under their change-in-control severance agreements. No payments are made under the severance agreements unless, within two years of the change in control, the named executive officer is involuntarily terminated or he or she voluntarily terminates for Good Reason. (See the description of Good Reason below.)

Traditional Termination Events
- Retirement or Retirement Eligible – Termination of a named executive officer who is at least 50 years old and has at least 10 years of credited service.
- Resignation – Voluntary termination of a named executive officer who is not retirement-eligible.
- Lay Off – Involuntary termination of a named executive officer not for cause, who is not retirement-eligible.
- Involuntary Termination – Involuntary termination of a named executive officer for cause. Cause includes individual performance below minimum performance standards and misconduct, such as violation of Gulf Power's Drug and Alcohol Policy.
- Death or Disability – Termination of a named executive officer due to death or disability.

Change-in-Control-Related Events
At the Southern Company or Gulf Power level:
- Southern Company Change-in-Control I – Acquisition by another entity of 20% or more of Common Stock, or following a merger with another entity Southern Company's stockholders own 65% or less of the entity surviving the merger.
- Southern Company Change-in-Control II – Acquisition by another entity of 35% or more of Common Stock, or following a merger with another entity Gulf Power's stockholders own less than 50% of Gulf Power surviving the merger.
- Southern Company Termination – A merger or other event and Southern Company is not the surviving company or the Common Stock is no longer publicly traded.
- Gulf Power Change in Control – Acquisition by another entity, other than another subsidiary of Southern Company, of 50% or more of the stock of Gulf Power, a merger with another entity and Gulf Power is not the surviving company, or the sale of substantially all the assets of Gulf Power.

At the employee level:

- Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason – Employment is terminated within two years of a change in control, other than for cause, or the employee voluntarily terminates for Good Reason. Good Reason for voluntary termination within two years of a change in control generally is satisfied when there is a material reduction in salary, performance-based compensation opportunity or benefits, relocation of over 50 miles, or a diminution in duties and responsibilities.

The following chart describes the treatment of different pay and benefit elements in connection with the Traditional Termination Events described above.

Program	Retirement/ Retirement Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Pension Benefits Plans	Benefits payable as described in the notes following the Pension Benefits table.	Same as Retirement.	Same as Retirement.	Same as Retirement.	Same as Retirement.
Annual Performance Pay Program	Pro-rated if terminate before 12/31.	Same as Retirement.	Forfeit.	Same as Retirement.	Forfeit.
Performance Dividend Program	Paid year of retirement plus two additional years.	Forfeit.	Forfeit.	Payable until options expire or exercised.	Forfeit.
Stock Options	Vest; expire earlier of original expiration date or five years.	Vested options expire in 90 days; unvested are forfeited.	Same as Lay Off.	Vest; expire earlier of original expiration or three years.	Forfeit.
Performance Shares	Pro-rated if retire prior to end of performance period.	Forfeit.	Forfeit.	Same as Retirement.	Forfeit.
Financial Planning Perquisite	Continues for one year.	Terminates.	Terminates.	Same as Retirement.	Terminates.

Program	Retirement/ Retirement Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Deferred Compensation Plan	Payable per prior elections (lump sum or up to 10 annual installments).	Same as Retirement.	Same as Retirement.	Payable to beneficiary or disabled participant per prior elections; amounts deferred prior to 2005 can be paid as a lump sum per benefit administration committee's discretion.	Same as Retirement.
Supplemental Benefit Plan – non-pension related	Payable per prior elections (lump sum or up to 20 annual installments).	Same as Retirement.	Same as Retirement.	Same as the Deferred Compensation Plan.	Same as Retirement.

The chart below describes the treatment of payments under pay and benefit programs under different change-in-control events, except the Pension Plan. The Pension Plan is not affected by change-in-control events.

Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Nonqualified Pension Benefits	All SERP-related benefits vest if participants vested in tax-qualified pension benefits; otherwise, no impact. SBP - pension-related benefits vest for all participants and single sum value of benefits earned to change-in-control date paid following termination or retirement.	Benefits vest for all participants and single sum value of benefits earned to the change-in-control date paid following termination or retirement.	Same as Southern Company Change-in-Control II.	Based on type of change-in-control event.
Annual Performance Pay Program	No program termination is paid at greater of target or actual performance. If program terminated within two years of change in control, pro-rated at target performance level.	Same as Southern Company Change-in-Control I.	Pro-rated at target performance level.	If not otherwise eligible for payment, if the program still in effect, pro-rated at target performance level.

Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Performance Dividend Program	No program termination is paid at greater of target or actual performance. If program terminated within two years of change in control, pro-rated at greater of target or actual performance level.	Same as Southern Company Change-in-Control I.	Pro-rated at greater of actual or target performance level.	If not otherwise eligible for payment, if the program is still in effect, greater of actual or target performance level for year of severance only.
Stock Options	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
Performance Shares	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
DCP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.
SBP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.
Severance Benefits	Not applicable.	Not applicable.	Not applicable.	One or two times base salary plus target annual performance-based pay.
Health Benefits	Not applicable.	Not applicable.	Not applicable.	Up to five years participation in group health plan plus payment of two or three years premium amounts.
Outplacement Services	Not applicable.	Not applicable.	Not applicable.	Six months.

Potential Payments

This section describes and estimates payments that would become payable to the named executive officers upon a termination or change in control as of December 31, 2010.

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2010 under the Pension Plan, the SBP-P, and the SERP are itemized in the chart below. The amounts shown under the column Retirement are amounts that would have become payable to the named executive officers that were retirement-eligible on December 31, 2010 and are the monthly Pension Plan benefits and the first of 10 annual installments from the SBP-P and the SERP. The amounts shown under the column Resignation or Involuntary Termination are the amounts that would have become payable to the named executive officers who were not retirement-eligible on December 31, 2010 and are the monthly Pension Plan benefits that would become payable as of the earliest possible date under the Pension Plan and the single sum value of benefits earned up to the termination date under the SBP-P, paid as a single payment rather than in 10 annual installments. Benefits under the SERP would be forfeited. The amounts shown that are payable to a spouse in the event of the death of the named executive officer are the monthly amounts payable to a spouse under the Pension Plan and the first of 10 annual installments from the SBP-P and the SERP. The amounts in this chart are very different from the pension values shown in the Summary Compensation Table and the Pension Benefits table. Those tables show the present values of all the benefits amounts anticipated to be paid over the lifetimes of the named executive officers and their spouses. Those plans are described in the notes following the Pension Benefits table. Of the named executive officers, Messrs. McCullough and Teel, and Ms. Terry were not retirement-eligible on December 31, 2010. The SRAs for Ms. Terry and Mr. Raymond contain additional service requirements for benefit eligibility which were not met as of December 31, 2010. Therefore neither was eligible to receive retirement benefits under those agreements. However, death benefits would be paid to a surviving spouse.

Name		**Retirement ($)**	**Resignation or Involuntary**	**Death (payments to a spouse) ($)**
S. N. Story	Pension	4,490	All plans treated as retiring	4,098
	SBP-P	120,287		120,287
	SERP	73,831		73,831
	Pension	2,947	Treated as retiring	2,658
P. C. Raymond	SBP-P	9,428	Treated as retiring	9,428
	SERP	17,107	Treated as retiring	17,107
	SRA	0	0	38,890
R.S. Teel	Pension	n/a	767	1,259
	SBP-P		22,922	3,731
	SERP		0	8,722
M. L. Burroughs	Pension	1,714	All plans treated as retiring	1,655
	SBP-P	0		0
	SERP	10,629		10,629
P. B. Jacob	Pension	5,880	All plans treated as retiring	3,813
	SBP-P	24,797		24,797
	SERP	26,494		26,494
T. J. McCullough	Pension	n/a	1,588	2,609
	SBP-P		54,834	6,813
	SERP		0	16,189
B. C. Terry	Pension	n/a	746	1,225
	SBP-P		18,648	3,055
	SERP		0	7,503
	SRA		0	44,471

As described in the Change-in-Control Chart, the only change in the form of payment, acceleration, or enhancement of the pension benefits is that the single sum value of benefits earned up to the change-in-control date under the SBP-P and the SERP could be paid as a single payment rather than in 10 annual installments. Also, the SERP benefits vest for participants who are not retirement-eligible upon a change in control. Estimates of the single sum payment that would have been made to the named executive officers, assuming termination as of December 31, 2010 following a change-in-control event, other than a Southern Company Change-in-Control I (which does not impact how pension benefits are paid), are itemized below. These amounts would be paid instead of the benefits shown in the Traditional Termination Events chart above; they are not paid in addition to those amounts.

	SBP-P ($)	SERP ($)	SRA ($)	Total ($)
S. N. Story	1,202,874	738,309	0	1,941,183
P. C. Raymond	94,281	171,066	388,903	654,250
R.S. Teel	22,380	52,314	0	74,694
M.L. Burroughs	0	106,287	0	106,287
P. B. Jacob	247,969	264,937	0	512,906
T. J. McCullough	53,537	127,219	0	180,756
B. C. Terry	18,207	44,719	266,680	329,606

The pension benefit amounts in the tables above were calculated as of December 31, 2010 assuming payments would begin as soon as possible under the terms of the plans. Accordingly, appropriate early retirement reductions were applied. Any unpaid annual performance-based compensation was assumed to be paid at 1.30 times the target level. Pension Plan benefits were calculated assuming each named executive officer chose a single life annuity form of payment, because that results in the greatest monthly benefit. The single sum values were based on a 4.25% discount rate.

Annual Performance Pay Program

The amount payable if a change in control had occurred on December 31, 2010 is the greater of target or actual performance. Because actual payouts for 2010 performance were below the target level, the amount that would have been payable was the target level amount as reported in the Grants of Plan-Based Awards table.

Performance Dividends

Because the assumed termination date is December 31, 2010, there is no additional amount that would be payable other than what was reported in the Summary Compensation Table. As described in the Traditional Termination Events chart, there is some continuation of benefits under the Performance Dividend Program for retirees.

However, under the Change-in-Control-Related Events, performance dividends are payable at the greater of target performance or actual performance. For the 2007-2010 performance-measurement period, actual performance exceeded target-level performance.

Stock Options and Performance Shares

Stock options and performance shares would be treated as described in the Termination and Change-in-Control charts above. Under a Southern Company Termination, all stock options and performance shares vest. In addition, if there is an Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason, stock options and performance shares vest. There is no payment associated with stock options or performance shares unless there is a Southern Company Termination and the participants' stock options or performance shares cannot be converted into surviving company awards. In that event, the value of outstanding stock options and performance shares would be paid to the named executive officers. For stock options, that value is the excess of the exercise price and the closing price of the Common Stock on December 31, 2010 and for performance shares, it is the closing price on December 31, 2010. The chart below shows the number of stock options for which vesting would be accelerated under a Southern Company Termination and the amount that would be payable under a Southern Company Termination if there were no conversion to the surviving company's stock options. It also shows the number and value of performance shares that would be paid.

	Number of Stock Options/ Performance Shares with Accelerated Vesting (#)	Total Number of Stock Options/Performance Shares Following Accelerated Vesting under a Southern Company Termination (#)	Total Payable in Cash under a Southern Company Termination without Conversion of Stock Options or Performance Shares ($)
S. N. Story	160,358/8,778	346,033/8,778	2,160,138
P. C. Raymond	46,934/2,824	93,974/2,824	644,361
R.S. Teel	27,376/1,568	64,697/1,568	408,422
M. L. Burroughs	7,062/401	12,297/401	79,597
P. B. Jacob	48,904/2,848	72,019/2,848	476,574
T. J. McCullough	26,321/1,501	53,133/1,501	338,345
B. C. Terry	48,247/2,824	84,379/2,824	565,336

DCP and SBP

The aggregate balances reported in the Nonqualified Deferred Compensation table would be payable to the named executive officers as described in the Traditional Termination and Change-in-Control-Related Events charts above. There is no enhancement or acceleration of payments under these plans associated with termination or change-in-control events, other than the lump-sum payment opportunity described in the above charts. The lump sums that would be payable are those that are reported in the Nonqualified Deferred Compensation table.

Health Benefits

Ms. Story and Messrs. Burroughs, Jacob, and Raymond are retirement-eligible. Health care benefits are provided to retirees and there is no incremental payment associated with the termination or change-in-control events. At the end of 2010, the other named executive officers were not retirement-eligible and thus health care benefits would not become available until each reaches age 50, except in the case of a change-in-control-related termination, as described in the Change-in-Control-Related Events chart. The estimated cost of providing two years of health insurance premiums is $11,067 for Ms. Terry, $33,200 for Mr. McCullough, and $29,515 for Mr. Teel.

Financial Planning Perquisite

Since Ms. Story and Messrs. Burroughs, Jacob, and Raymond are retirement-eligible, an additional year of the Financial Planning perquisite, which is set at a maximum of $8,700 per year, will be provided after retirement. Ms. Terry and Messrs. McCullough and Teel are not retirement-eligible.

There are no other perquisites provided to the named executive officers under any of the traditional termination or change-in-control-related events.

Severance Benefits

The named executive officers are participants in a change-in-control severance plan. The plan provides severance benefits, including outplacement services, if within two years of a change in control, they are involuntarily terminated, not for Cause, or they voluntarily terminate for Good Reason. The severance benefits are not paid unless the named executive officer releases the employing company from any claims he or she may have against the employing company.

The estimated cost of providing the six months of outplacement services is $6,000 per named executive officer. The severance payment is two times the base salary and target payout under the annual Performance Pay Program for Ms. Story and one times the base salary and target payout under the annual Performance Pay Program for the other named executive officers.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2010 in connection with a change in control.

	Severance Amount ($)
S. N. Story	1,373,647
P. C. Raymond	393,198
R.S. Teel	325,815
M.L. Burroughs	250,895
P. B. Jacob	362,626
T. J. McCullough	311,762
B. C. Terry	359,756

COMPENSATION RISK ASSESSMENT

Southern Company reviewed its compensation policies and practices, including those of Gulf Power, and concluded that excessive risk-taking is not encouraged. This conclusion was based on an assessment of the mix of pay components and performance goals, the annual pay/performance analysis by the Compensation Committee's consultant, stock ownership requirements, compensation governance practices, and the "claw-back" provision. The assessment was reviewed with the Compensation Committee.

DIRECTOR COMPENSATION

Only non-employee directors of Gulf Power are compensated for service on the board of directors. Prior to April 1, 2010, the pay components for non-employee directors were:

Annual cash retainer:	$12,000 per year
Annual equity grant:	340 shares of Common Stock in quarterly grants of 85 shares
Board meeting fees:	$1,200 for participation in a meeting of the board
Committee meeting fees:	$1,000 for participation in a meeting of a committee of the board

Beginning April 1, 2010, the pay components for non-employee directors are:

Annual cash retainer:	$22,000 per year
Annual stock retainer:	$19,500 per year in Common Stock
Board meeting fees:	If more than five meetings are held in a calendar year, $1,200 will be paid for participation beginning with the sixth meeting.
Committee meeting fees:	If more than five meetings of any one committee are held in a calendar year, $1,000 will be paid for participation in each meeting of that committee beginning with the sixth meeting.

DIRECTOR DEFERRED COMPENSATION PLAN

Any deferred quarterly equity grants or stock retainers are required to be deferred in the Deferred Compensation Plan For Directors of Gulf Power Company (Director Deferred Compensation Plan) and are invested in Common Stock units which earn dividends as if invested in Common Stock. Earnings are reinvested in additional stock units. Upon leaving the board, distributions are made in shares of Common Stock.

In addition, directors may elect to defer up to 100% of their remaining compensation in the Director Deferred Compensation Plan until membership on the board ends. Deferred compensation may be invested as follows, at the director's election:

- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in shares of Common Stock upon leaving the board

- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in cash upon leaving the board
- at prime interest which is paid in cash upon leaving the board

All investments and earnings in the Director Deferred Compensation Plan are fully vested and, at the election of the director, may be distributed in a lump sum payment or in up to 10 annual distributions after leaving the board.

DIRECTOR COMPENSATION TABLE

The following table reports all compensation to Gulf Power's non-employee directors during 2010, including amounts deferred in the Director Deferred Compensation Plan. Non-employee directors do not receive Non-Equity Incentive Plan Compensation, and there is no pension plan for non-employee directors.

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(3)	All Other Compensation ($)(4)	Total ($)
C. LeDon Anchors (5)	5,700	4,327	0	845	10,872
Allan G. Bense (6)	31,125	0	0	114	31,239
Deborah H. Calder (6)	33,525	0	0	61	33,586
William C. Cramer, Jr.	0	44,752	0	58	44,810
Fred C. Donovan, Sr. (5)	71,567	30,777	0	641	102,985
J. Mort O'Sullivan III (6)	6,100	15,850	0	63	22,013
William A. Pullum	0	43,552	0	58	43,610
Winston E. Scott	45,770	0	0	58	45,828

(1) Includes amounts voluntarily deferred in the Director Deferred Compensation Plan.
(2) Includes fair market value of equity grants on grant dates. All such stock awards are vested immediately upon grant.
(3) Above-market earnings on amounts invested in the Director Deferred Compensation Plan. Above-market earnings are defined by the SEC as any amount above 120% of the applicable federal long-term rate as prescribed under Section 1274(d) of the Code.
(4) Consists of gifts and reimbursement for taxes.
(5) Mr. Anchors retired effective March 22, 2010 and Mr. Donovan retired effective August 4, 2010.
(6) Mr. Bense and Ms. Calder were elected directors in April 2010 and Mr. O'Sullivan became a director in June 2010.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Compensation Committee is made up of non-employee directors of Southern Company who have never served as executive officers of Southern Company or Gulf Power. During 2010, none of Southern Company's or Gulf Power's executive officers served on the board of directors of any entities whose directors or officers serve on the Compensation Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership of Certain Beneficial Owners. Southern Company is the beneficial owner of 100% of the outstanding common stock of Gulf Power.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	The Southern Company 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308		100%
	Registrant: Gulf Power	4,142,717	

Security Ownership of Management. The following tables show the number of shares of Common Stock owned by the directors, nominees, and executive officers as of December 31, 2010. It is based on information furnished by the directors, nominees, and executive officers. The shares owned by all directors, nominees, and executive officers as a group constitute less than one percent of the total number of shares outstanding on December 31, 2010.

		Shares Beneficially Owned Include:	
Name of Directors, Nominees, and Executive Officers	**Shares Beneficially Owned (1)**	**Deferred Stock Units (2)**	**Shares Individuals Have Rights to Acquire Within 60 Days (3)**
Susan N. Story	266,503	0	259,909
Allan G. Bense	419	0	0
Deborah H. Calder	419	0	0
William C. Cramer, Jr.	10,942	10,942	0
J. Mort O'Sullivan III	460	460	0
William A. Pullum	12,325	12,325	0
Winston E. Scott	2,571	0	0
P. Bernard Jacob	52,479	0	45,588
Michael L. Burroughs	10,840	0	8,598
Richard S. Teel	50,701	0	50,167
Bentina C. Terry	60,335	0	58,168
Directors, Nominees, and Executive Officers as a group (11 people)	467,994	23,727	422,430

(1) "Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security and/or investment power with respect to a security or any combination thereof.
(2) Indicates the number of deferred stock units held under the Director Deferred Compensation Plan.
(3) Indicates shares of Common Stock that certain executive officers have the right to acquire within 60 days. Shares indicated are included in the Shares Beneficially Owned column.

Changes in Control. Southern Company and Gulf Power know of no arrangements which may at a subsequent date result in any change-in-control.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Transactions with Related Persons. None.

Review, Approval or Ratification of Transactions with Related Persons.

Gulf Power does not have a written policy pertaining solely to the approval or ratification of "related party transactions." Southern Company has a Code of Ethics as well as a Contract Guidance Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for most transactions above $10,000 or approval based on documented business needs for sole sourcing arrangements. The approval and ratification of any related party transactions would be subject to these written policies and procedures which include a determination of the need for the goods and services; preparation and evaluation of requests for proposals by supply chain management; the writing of contracts; controls and guidance regarding the evaluation of the proposals; and negotiation of contract terms and conditions. As appropriate, these contracts are also reviewed by individuals in the legal, accounting and/or risk management/ services departments prior to being approved by the responsible individual. The responsible individual will vary depending on the department requiring the goods and services, the dollar amount of the contract and the appropriate individual within that department who has the authority to approve a contract of the applicable dollar amount.

Director Independence.

The board of directors of Gulf Power consisted of six non-employee directors (Ms. Deborah H. Calder and Messrs Allan G. Bense, William C. Cramer, Jr., J. Mort O'Sullivan, III, William A. Pullum, and Winston E. Scott) and Ms. Story, the president and chief executive officer of Gulf Power during 2010.

Southern Company owns all of Gulf Power's outstanding common stock. Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance, including requirements relating to certain board committees. Gulf Power has voluntarily complied with certain of the NYSE's listing standards relating to corporate governance where such compliance was deemed to be in the best interests of Gulf Power's shareholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents the fees billed to Gulf Power and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2010 and 2009:

	2010	2009
	(in thousands)	
Gulf Power		
Audit Fees (1)	$1,450	$1,308
Audit-Related Fees	0	0
Tax Fees	0	0
All Other Fees	0	0
Total	$1,450	$1,308
Southern Power		
Audit Fees (1)	$1,134	$1,136
Audit-Related Fees (2)	0	38
Tax Fees	0	0
All Other Fees	0	0
Total	$1,134	$1,174

(1) Includes services performed in connection with financing transactions.
(2) Includes other non-statutory audit services and accounting consultations.

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided by Deloitte & Touche LLP in fiscal years 2010 and 2009 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

[This page intentionally left blank]

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Financial Statements and Financial Statement Schedules:

Management’s Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Management’s Report on Internal Control Over Financial Reporting for Alabama Power is listed under Item 8 herein.

Management’s Report on Internal Control Over Financial Reporting for Georgia Power is listed under Item 8 herein.

Management’s Report on Internal Control Over Financial Reporting for Gulf Power is listed under Item 8 herein.

Management’s Report on Internal Control Over Financial Reporting for Mississippi Power is listed under Item 8 herein.

Management’s Report on Internal Control Over Financial Reporting for Southern Power and Subsidiary Companies is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statements and financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power and Mississippi Power, as well as the Report of Independent Registered Public Accounting Firm on the financial statements of Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power are listed in the Index to the Financial Statement Schedules at page S-1.

(2) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power are listed in the Exhibit Index at page E-1.

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By: Thomas A. Fanning
Chairman, President, and
Chief Executive Officer

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Thomas A. Fanning
Chairman, President,
Chief Executive Officer, and Director
(Principal Executive Officer)

Art P. Beattie
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

W. Ron Hinson
Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:	
Juanita Powell Baranco	*Donald M. James*
Jon A. Boscia	*Dale E. Klein*
Henry A. Clark III	*J. Neal Purcell*
H. William Habermeyer, Jr.	*William G. Smith, Jr.*
Veronica M. Hagen	*Steven R. Specker*
Warren A. Hood, Jr.	*Larry D. Thompson*

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By: Charles D. McCrary
President and Chief Executive Officer

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Charles D. McCrary
President, Chief Executive Officer, and Director
(Principal Executive Officer)

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

Anita Allcorn-Walker
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong	*Malcolm Portera*
Ralph D. Cook	*Robert D. Powers*
David J. Cooper, Sr.	*C. Dowd Ritter*
Thomas A. Fanning	*James H. Sanford*
John D. Johns	*John Cox Webb, IV*
Patricia M. King	
James K. Lowder	

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By: W. Paul Bowers
President and Chief Executive Officer

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

W. Paul Bowers
President, Chief Executive Officer, and Director
(Principal Executive Officer)

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

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

Directors:

Robert L. Brown, Jr.	*Charles K. Tarbutton*
Anna R. Cablik	*Beverly D. Tatum*
Thomas A. Fanning	*D. Gary Thompson*
Stephen S. Green	*Richard W. Ussery*
Jimmy C. Tallent	*E. Jenner Wood, III*

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By: Mark A. Crosswhite
President and Chief Executive Officer

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Mark A. Crosswhite
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Richard S. Teel
Vice President and Chief Financial Officer
(Principal Financial Officer)

Constance J. Erickson
Comptroller
(Principal Accounting Officer)

Directors:

Allan G. Bense	*J. Mort O'Sullivan, III*
Deborah H. Calder	*William A. Pullum*
William C. Cramer, Jr.	*Winston E. Scott*

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By: Edward Day, VI
President and Chief Executive Officer

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Edward Day, VI
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Moses H. Feagin
Vice President, Treasurer, and
Chief Financial Officer
(Principal Financial Officer)

Cynthia F. Shaw
Comptroller
(Principal Accounting Officer)

Directors:

Carl J. Chaney	*Martha D. Saunders*
L. Royce Cumbest	*Philip J. Terrell*
Christine L. Pickering	*Marion L. Waters*

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN POWER COMPANY

By: Oscar C. Harper IV
President and Chief Executive Officer

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Oscar C. Harper IV
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Michael W. Southern
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Janet J. Hodnett
Comptroller and Corporate Secretary
(Principal Accounting Officer)

Directors:

Art P. Beattie	*G. Edison Holland, Jr.*
Thomas A. Fanning	*Anthony J. Topazi*

By:

(Melissa K. Caen, Attorney-in-fact)

Date: February 25, 2011

[This page intentionally left blank]

INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedule II **Page**

Schedules I through V not listed above are omitted as not applicable or not required. A Schedule II for Southern Power Company and Subsidiary Companies is not being provided because there were no reportable items for the three-year period ended December 31, 2010. Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2010, 2009, AND 2008
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2010	$24,568	$62,137	$-	$61,786 (Note)	$24,919
2009	26,326	58,722	-	60,480 (Note)	24,568
2008	22,142	60,184	-	56,000 (Note)	26,326

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2010, 2009, AND 2008
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2010	$9,551	$18,271	$-	$18,220 (Note)	$9,602
2009	8,882	21,951	-	21,282 (Note)	9,551
2008	7,988	20,824	-	19,930 (Note)	8,882

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2010, 2009, AND 2008
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2010	$9,856	$37,004	$-	$35,762 (Note)	11,098
2009	10,732	29,088	-	29,964 (Note)	9,856
2008	7,636	31,219	-	28,123 (Note)	10,732

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GULF POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2010, 2009, AND 2008
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2010	$1,913	$3,907	$-	$3,806 (Note)	$2,014
2009	2,188	3,753	-	4,028 (Note)	1,913
2008	1,711	3,893	-	3,416 (Note)	2,188

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2010, 2009, AND 2008
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2010	$ 940	$1,519	$-	$1,821 (Note)	$ 638
2009	1,039	2,356	-	2,455 (Note)	940
2008	924	2,372	-	2,257 (Note)	1,039

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

EXHIBIT INDEX

The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

(3) Articles of Incorporation and By-Laws

Southern Company

(a) 1 - Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through May 27, 2010. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A, in Certificate of Notification, File No. 70-8181, as Exhibit A, and in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.1.)

(a) 2 - By-laws of Southern Company as amended effective May 26, 2010, and as presently in effect. (Designated in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.2.)

Alabama Power

(b) 1 - Charter of Alabama Power and amendments thereto through April 25, 2008. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Alabama Power's Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Alabama Power's Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1, in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b)(1), in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 12, 2007, File No. 1-3164, as Exhibit 4.5, in Form 8-K dated October 17, 2007, File No. 1-3164, as Exhibit 4.5, and in Alabama Power's Form 10-Q for the quarter ended March 31, 2008, File No. 1-3164, as Exhibit 3(b)1.)

(b) 2 - By-laws of Alabama Power as amended effective January 26, 2007, and as presently in effect. (Designated in Form 8-K dated January 26, 2007, File No 1-3164, as Exhibit 3(b)2.)

Georgia Power

(c) 1 - Charter of Georgia Power and amendments thereto through October 9, 2007. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Georgia Power's Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December

10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Georgia Power's Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Georgia Power's Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2, in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1, and in Form 8-K dated October 3, 2007, File No. 1-6468, as Exhibit 4.5.)

(c) 2 - By-laws of Georgia Power as amended effective May 20, 2009, and as presently in effect. (Designated in Form 8-K dated May 20, 2009, File No. 1-6468, as Exhibit 3(c)2.)

Gulf Power

(d) 1 - Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through October 17, 2007. (Designated in Form 8-K dated October 27, 2005, File No. 0-2429, as Exhibit 3.1, in Form 8-K dated November 9, 2005, File No. 0-2429, as Exhibit 4.7, and in Form 8-K dated October 16, 2007, File No. 0-2429, as Exhibit 4.5.)

(d) 2 - By-laws of Gulf Power as amended effective November 2, 2005, and as presently in effect. (Designated in Form 8-K dated November 2, 2005, File No. 0-2429, as Exhibit 3.2.)

Mississippi Power

(e) 1 - Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 0-6849, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 0-6849, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 0-6849, as Exhibit 4(b)-3, in Mississippi Power's Form 10-K for the year ended December 31, 1997, File No. 0-6849, as Exhibit 3(e)2, in Mississippi Power's Form 10-K for the year ended December 31, 2000, File No. 0-6849, as Exhibit 3(e)2, and in Form 8-K dated March 3, 2004, File No. 0-6849, as Exhibit 4.6.)

(e) 2 - By-laws of Mississippi Power as amended effective February 28, 2001, and as presently in effect. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2001, File No. 0-6849, as Exhibit 3(e)2.)

Southern Power

(f) 1 - Certificate of Incorporation of Southern Power dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)

(f) 2 - By-laws of Southern Power effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

Southern Company

(a) 1 - Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through September 17, 2010. (Designated in Form 8-K dated January 11, 2006, File No. 1-3526, as

Exhibits 4.1 and 4.2, in Form 8-K dated March 20, 2007, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 13, 2008, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated May 11, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated October 19, 2009, File No. 1-3526, as Exhibit 4.2, and in Form 8-K dated September 13, 2010, File No. 1-3526, as Exhibit 4.2.)

Alabama Power

(b) 1 - Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 18, 1999, File No. 1-3164, as Exhibit 4.2 and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibits 4.9-A and 4.9-B.)

(b) 2 - Senior Note Indenture dated as of December 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through October 5, 2010. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 20, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 17, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 11, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 8, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 16, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 7, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 28, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 12, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 19, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 13, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 21, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 11, 2000, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 22, 2001, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated June 21, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated October 16, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated November 20, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 15, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 10, 2004, File No. 1-3164, as Exhibit 4.2 in Form 8-K dated April 7, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 19, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 9, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 8, 2005, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 11, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 13, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 1, 2006, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 9, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated June 7, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 30, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 11, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 8, 2008, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated February 26, 2009, File No. 1-3164 as Exhibit 4.2, and in Form 8-K dated September 27, 2010, File No. 1-3164, as Exhibit 4.2.)

(b) 3 - Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)

(b) 4 - Guarantee Agreement relating to Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)

Georgia Power

(c) 1 - Subordinated Note Indenture dated as of June 1, 1997, between Georgia Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through January 23, 2004. (Designated in Certificate of Notification, File No. 70-8461, as Exhibits D and E, in Form 8-K dated February 17, 1999, File No. 1-6468, as Exhibit 4.4, in Form 8-K dated June 13, 2002, File No. 1-6468, as Exhibit 4.4, in Form 8-K dated October 30, 2002, File No. 1-6468, as Exhibit 4.4 and in Form 8-K dated January 15, 2004, File No. 1-6468, as Exhibit 4.4.)

(c) 2 - Senior Note Indenture dated as of January 1, 1998, between Georgia Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through January 19, 2011. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 and 4.2, in Forms 8-K each dated November 19, 1998, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 3, 1999, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated February 15, 2000, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated January 26, 2001, File No. 1-6469 as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 16, 2001, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated May 1, 2001, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 27, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 15, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 13, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 21, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibits 4.1, 4.2 and 4.3, in Form 8-K dated September 8, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated September 23, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated January 12, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated February 12, 2004, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated August 11, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated January 13, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated April 12, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated November 30, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated December 8, 2006, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 6, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 4, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 18, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated July 10, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 24, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 29, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 5, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 12, 2008, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 4, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated December 8, 2009, File No. 1-6468, as Exhibit 4.2, and in Form 8-K dated March 9, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 24, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 26, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated September 20, 2010, File No. 1-6468, as Exhibit 4.2, and in Form 8-K dated January 13, 2011, File No. 1-6468, as Exhibit 4.2.)

(c) 3 - Senior Note Indenture dated as of March 1, 1998 between Georgia Power, as successor to Savannah Electric, and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through June 30, 2006. (Designated in Form 8-K dated March 9, 1998, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated May 8, 2001, File No. 1-5072, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated November 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated December 10, 2003, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated

December 2, 2004, File No. 1-5072, as Exhibit 4.1, and in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 4.2.)

(c) 4 - Amended and Restated Trust Agreement of Georgia Power Capital Trust VII dated as of January 1, 2004. (Designated in Form 8-K dated January 15, 2004, as Exhibit 4.7-A.)

(c) 5 - Guarantee Agreement relating to Georgia Power Capital Trust VII dated as of January 1, 2004. (Designated in Form 8-K dated January 15, 2004, as Exhibit 4.11-A.)

Gulf Power

(d) 1 - Senior Note Indenture dated as of January 1, 1998, between Gulf Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through September 17, 2010. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated August 17, 1999, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 31, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated October 5, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated January 18, 2002, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated March 21, 2003, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 10, 2003, File No. 001-31737, as Exhibits 4.1 and 4.2, in Form 8-K dated September 5, 2003, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated April 6, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated September 13, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated August 11, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated November 28, 2006, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 5, 2007, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 22, 2009, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated April 6, 2010, File No. 001-31737, as Exhibit 4.2, and in Form 8-K dated September 9, 2010, File No. 001-31737, as Exhibit 4.2.)

Mississippi Power

(e) 1 - Senior Note Indenture dated as of May 1, 1998 between Mississippi Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through March 6, 2009. (Designated in Form 8-K dated May 14, 1998, File No. 001-11229, as Exhibits 4.1, 4.2(a) and 4.2(b), in Form 8-K dated March 22, 2000, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 12, 2002, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated April 24, 2003, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated June 24, 2005, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 8, 2007, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 001-11229, as Exhibit 4.2, and in Form 8-K dated March 3, 2009, File No. 001-11229, as Exhibit 4.2.)

Southern Power

(f) 1 - Senior Note Indenture dated as of June 1, 2002, between Southern Power and The Bank of New York Mellon (formerly known as The Bank of New York), as Trustee, and indentures supplemental thereto through November 21, 2006. (Designated in Registration No. 333-98553 as Exhibits 4.1 and 4.2 and in Southern Power's Form 10-Q for the quarter ended June 30, 2003, File No. 333-98553, as Exhibit 4(g)1, and in Form 8-K dated November 13, 2006, File No. 333-98553, as Exhibit 4.2.)

(10) Material Contracts

Southern Company

(a) 1 - Amended and Restated Southern Company Omnibus Incentive Compensation Plan, effective January 1, 2007. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3536, as Exhibit 10(a)1.)

* (a) 2 - Form of 2010 Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan.

(a) 3 - Deferred Compensation Plan for Directors of The Southern Company, Amended and Restated effective January 1, 2008. (Designated in Southern Company's Form 10-K for the year ended December 31, 2007, File No. 1-3536, as Exhibit 10(a)3.)

(a) 4 - Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3536, as Exhibit 10(a)4 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3536, as Exhibit 10(a)5.)

(a) 5 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2004, File No. 1-3526, as Exhibit 10(a)2.)

(a) 6 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3536, as Exhibit 10(a)6 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3536, as Exhibit 10(a)(8).)

(a) 7 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3536, as Exhibit 10(a)7 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3536, as Exhibit 10(a)10.)

* (a) 8 - Termination of Amended and Restated Change in Control Agreement effective February 22, 2011 between Southern Company, Alabama Power, and Charles D. McCrary.

* (a) 9 - Separation and Release Agreement between Michael D. Garrett and Georgia Power effective February 22, 2011.

(a) 10 - The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1.)

(a) 11 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3536, as Exhibit 10(a)16.)

(a) 12 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company,

Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3536, as Exhibit 10(a)18.)

#	(a)	13	-	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3536, as Exhibit 10(a)20.)
#	* (a)	14	-	Termination of Amended and Restated Change in Control Agreement effective February 22, 2011 between Southern Company, SCS, and Thomas A. Fanning.
#	(a)	15	-	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3536, as Exhibit 10(a)23 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3536, as Exhibit 10(a)22.)
#	* (a)	16	-	Second Amendment to The Southern Company Senior Executive Change in Control Severance Plan effective February 23, 2011.
#	(a)	17	-	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3536, as Exhibit 10(a)24 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3536, as Exhibit 10(a)24.)
#	* (a)	18	-	Termination of Amended and Restated Change in Control Agreement effective February 22, 2011 between Southern Company, SCS, and William Paul Bowers.
#	(a)	19	-	Form of Restricted Stock Award Agreement. (Designated in Form 10-Q for the quarter ended September 30, 2007, File No. 1-3526, as Exhibit 10(a)1.)
#	* (a)	20	-	Base Salaries of Named Executive Officers.
#	(a)	21	-	Summary of Non-Employee Director Compensation Arrangements. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)27.)
#	(a)	22	-	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Form 8-K dated February 9, 2010, File No. 1-3526, as Exhibit 10.1.)
#	(a)	23	-	Restricted Stock Award Agreement between Southern Company and W. Paul Bowers dated July 27, 2010. (Designated in Form 10-Q for the quarter ended September 30, 2010, File No. 1-3526, as Exhibit 10(a)2.)

Alabama Power

	(b)	1	-	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. (Designated in Form 10-Q for the quarter ended March 31, 2007, File No. 1-3164, as Exhibit 10(b)5.)

(b) 2 - Amended and Restated Southern Company Omnibus Incentive Compensation Plan, effective January 1, 2007. See Exhibit 10(a)1 herein.

(b) 3 - Form of 2010 Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.

(b) 4 - Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.

(b) 5 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

(b) 6 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.

(b) 7 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.

(b) 8 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)17 herein.

(b) 9 - Deferred Compensation Plan for Directors of Alabama Power Company, Amended and Restated effective January 1, 2008. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1.)

(b) 10 - The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.

(b) 11 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.

(b) 12 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.

(b) 13 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.

(b) 14 - Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.

(b) 15 - Termination of Amended and Restated Change in Control Agreement effective February 22, 2011 between Southern Company, Alabama Power, and Charles D. McCrary. See Exhibit 10(a)8 herein.

#	(b) 16	-	Deferred Compensation Agreement between Southern Company, Alabama Power, and SCS and Mark A. Crosswhite dated July 30, 2008. Designated in Alabama Power's Form 10-K for the year ended December 31, 2009, File No. 1-3164, as Exhibit 10(b)21.)
#	* (b) 17	-	Base Salaries of Named Executive Officers.
#	(b) 18	-	Summary of Non-Employee Director Compensation Arrangements. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2010, File No. 1-3164, as Exhibit 10(b)1.)
#	(b) 19	-	Form of Restricted Stock Award Agreement. See Exhibit 10(a)19 herein.
#	(b) 20	-	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)22 herein.
#	(b) 21	-	Deferred Compensation Agreement between Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS and Philip C. Raymond dated September 15, 2010. (Designated in Alabama Power's Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b)2.)
#	(b) 22	-	Consulting Agreement between Jerry L. Stewart and SCS dated October 11, 2010. (Designated in Alabama Power's Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b)3.)
#	(b) 23	-	Second Amendment to The Southern Company Senior Executive Change in Control Severance Plan effective February 23, 2011. Exhibit 10(a)16 herein.

Georgia Power

	(c) 1	-	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.
	(c) 2	-	Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)
	(c) 3	-	Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)
	(c) 4	-	Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)
#	(c) 5	-	Amended and Restated Southern Company Omnibus Incentive Compensation Plan, effective January 1, 2007. See Exhibit 10(a)1 herein.
#	(c) 6	-	Form of 2010 Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(c) 7	-	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(c) 8	-	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

(c) 9 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.

(c) 10 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.

(c) 11 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)17 herein.

(c) 12 - Deferred Compensation Plan For Directors of Georgia Power Company, Amended and Restated Effective January 1, 2008. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-6468, as Exhibit 10(c)12.)

(c) 13 - The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.

(c) 14 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.

(c) 15 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.

(c) 16 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.

(c) 17 - Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.

* (c) 18 - Base Salaries of Named Executive Officers.

(c) 19 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Georgia Power's Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)26.)

(c) 20 - Form of Restricted Stock Award Agreement. See Exhibit 10(a)19 herein.

(c) 21 - Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for OPC, MEAG Power, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site, Amendment No. 1 thereto dated as of December 11, 2009, Amendment No. 2 thereto dated as of January 15, 2010, and Amendment No. 3 thereto dated as of February 23, 2010. (Georgia Power requested confidential treatment for certain portions of these documents pursuant to applications for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filings and filed them separately with the SEC.) (Designated in Form 10-Q/A for the quarter ended June 30, 2008, File No. 1-6468, as Exhibit 10(c)1, in Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)29, and in Georgia Power's Form 10-Q for the quarter ended March 31, 2010, File No. 1-6468, as Exhibits 10(c)1 and 10(c)2.)

(c) 22 - Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)22 herein.

(c) 23 - Restricted Stock Award Agreement between Southern Company and W. Paul Bowers dated July 27, 2010. See Exhibit 10(a)23 herein.

(c) 24 - Termination of Amended and Restated Change in Control Agreement effective February 22, 2011 between Southern Company, SCS, and William Paul Bowers. See Exhibit 10(a)18 herein.

(c) 25 - Second Amendment to The Southern Company Senior Executive Change in Control Severance Plan effective February 23, 2011. See Exhibit 10(a)16 herein.

(c) 26 - Separation and Release Agreement between Michael D. Garrett and Georgia Power Company effective February 22, 2011. See Exhibit 10(a)9 herein.

Gulf Power

(d) 1 - Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.

(d) 2 - Unit Power Sales Agreement dated July 19, 1988, between FPC and Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(d).)

(d) 3 - Amended Unit Power Sales Agreement dated July 20, 1988, between FP&L and Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(e).)

(d) 4 - Amended Unit Power Sales Agreement dated August 17, 1988, between Jacksonville Electric Authority and Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(f).)

(d) 5 - Amended and Restated Southern Company Omnibus Incentive Compensation Plan, effective January 1, 2007. See Exhibit 10(a)1 herein.

(d) 6 - Form of 2010 Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.

(d) 7 - Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.

(d) 8 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

#	(d) 9	-	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(d) 10	-	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)17 herein.
#	(d) 11	-	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(d) 12	-	Deferred Compensation Plan For Outside Directors of Gulf Power Company, Amended and Restated effective January 1, 2008. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2008, File No. 0-2429, as Exhibit 10(d)1.)
#	(d) 13	-	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(d) 14	-	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(d) 15	-	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(d) 16	-	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(d) 17	-	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	* (d) 18	-	Base Salaries of Named Executive Officers.
#	(d) 19	-	Summary of Non-Employee Director Compensation Arrangements. (Designated in Gulf Power's Form 10-Q for the quarter ended June 30, 2010, File No. 001-31737, as Exhibit 10(d)1.)
#	(d) 20	-	Form of Restricted Stock Award Agreement. See Exhibit 10(a)19 herein.
	(d) 21	-	Power Purchase Agreement between Gulf Power and Shell Energy North America (US), L.P. dated March 16, 2009. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2009, File No. 001-31737, as Exhibit 10(d)1.) (Gulf Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Gulf Power omitted such portions from this filing and filed them separately with the SEC.)
#	(d) 22	-	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)22 herein.

(d) 23 - Deferred Compensation Agreement between Southern Company, Georgia Power, Gulf Power, and Southern Nuclear and Bentina C. Terry dated August 1, 2010. (Designated in Gulf Power's Form 10-Q for the quarter ended September 30, 2010, File No. 001-31737, as Exhibit 10(d)2.)

(d) 24 - Deferred Compensation Agreement between Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS and Philip C. Raymond dated September 15, 2010. See Exhibit 10(b)21 herein.

(d) 25 - Second Amendment to The Southern Company Senior Executive Change in Control Severance Plan effective February 23, 2011. See Exhibit 10(a)16 herein.

Mississippi Power

(e) 1 - Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.

(e) 2 - Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 1981, File No. 0-6849, as Exhibit 10(f), in Mississippi Power's Form 10-K for the year ended December 31, 1982, File No. 0-6849, as Exhibit 10(f)(2), and in Mississippi Power's Form 10-K for the year ended December 31, 1983, File No. 0-6849, as Exhibit 10(f)(3).)

(e) 3 - Amended and Restated Southern Company Omnibus Incentive Compensation Plan, effective January 1, 2007. See Exhibit 10(a)1 herein.

(e) 4 - Form of 2010 Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.

(e) 5 - Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.

(e) 6 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

(e) 7 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.

(e) 8 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)17 herein.

(e) 9 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.

(e) 10 - Deferred Compensation Plan for Outside Directors of Mississippi Power Company, Amended and Restated effective January 1, 2008. (Designated in Mississippi Power's Form 10-Q for the quarter ended March 31, 2008, File No. 0-6849 as Exhibit 10(e)1.)

(e) 11 - The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.

\# (e) 12 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.

\# (e) 13 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.

\# (e) 14 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.

\# (e) 15 - Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.

\# * (e) 16 - Base Salaries of Named Executive Officers.

\# (e) 17 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2009, File No. 001-11229, as Exhibit 10(e)22.)

\# (e) 18 - Form of Restricted Stock Award Agreement. See Exhibit 10(a)19 herein.

(e) 19 - Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2008, File No. 001-11229, as Exhibit 10(e)22.) (Mississippi Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Mississippi Power omitted such portions from this filing and filed them separately with the SEC.)

\# (e) 20 - Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)22 herein.

\# (e) 21 - Retention Agreement between Edward Day, VI and SCS dated January 22, 2008, Amendment to Retention Agreement dated December 12, 2008, and Amendment of Retention Agreement dated July 29, 2010. (Designated in Mississippi Power's Form 10-Q for the quarter ended September 30, 2010, File No. 001-11229, as Exhibit 10(e)2.)

\# (e) 22 - Second Amendment to The Southern Company Senior Executive Change in Control Severance Plan effective February 23, 2011. See Exhibit 10(a)16 herein.

Southern Power

(f) 1 - Service contract dated as of January 1, 2001, between SCS and Southern Power. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)(2).)

(f) 2 - Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.

(f) 3 - Amended and Restated Power Purchase Agreement between Southern Power and Georgia Power at Plant Autaugaville dated as of August 6, 2001. (Designated in Registration No. 333-98553 as Exhibit 10.19.)

(f) 4 - Multi-Year Credit Agreement dated as of July 7, 2006 by and among Southern Power, the Lenders (as defined therein), Citibank, N.A., as Administrative Agent, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as Initial Issuing Bank and Amendment Number One thereto. (Designated in Southern Power's Form 10-Q for the quarter ended June 30, 2006, File No. 333-98553, as Exhibit 10(f)1 and in Form 10-Q for the quarter ended June 30, 2007, File No. 333-98553, as Exhibit 10(f)2.) (Omits schedules and exhibits. Southern Power agreed to provide supplementally the omitted schedules and exhibits to the SEC upon request.)

(14) Code of Ethics

Southern Company

(a) - The Southern Company Code of Ethics. (Designated in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3536, as Exhibit 14(a).)

Alabama Power

(b) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Georgia Power

(c) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Gulf Power

(d) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Mississippi Power

(e) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Southern Power

(f) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

(21) Subsidiaries of Registrants

Southern Company

* (a) - Subsidiaries of Registrant.

Alabama Power

(b) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Georgia Power

(c) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Gulf Power

(d) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Mississippi Power

(e) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Southern Power

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

(23) Consents of Experts and Counsel

Southern Company

* (a) 1 - Consent of Deloitte & Touche LLP.

Alabama Power

* (b) 1 - Consent of Deloitte & Touche LLP.

Georgia Power

* (c) 1 - Consent of Deloitte & Touche LLP.

Gulf Power

* (d) 1 - Consent of Deloitte & Touche LLP.

Mississippi Power

* (e) 1 - Consent of Deloitte & Touche LLP.

Southern Power

* (f) 1 - Consent of Deloitte & Touche LLP.

(24) Powers of Attorney and Resolutions

Southern Company

* (a) - Power of Attorney and resolution.

Alabama Power

* (b) - Power of Attorney and resolution.

Georgia Power

* (c) - Power of Attorney and resolution.

Gulf Power

* (d) 1 - Power of Attorney and resolution.

* (d) 2 - Power of Attorney for Mark A. Crosswhite.

Mississippi Power

* (e) - Power of Attorney and resolution.

Southern Power

* (f) - Power of Attorney and resolution.

(31) Section 302 Certifications

Southern Company

* (a) 1 - Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (a) 2 - Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

* (b) 1 - Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (b) 2 - Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Georgia Power

* (c) 1 - Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (c) 2 - Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Gulf Power

* (d) 1 - Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (d) 2 - Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

* (e) 1 - Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (e) 2 - Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Power

* (f) 1 - Certificate of Southern Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (f) 2 - Certificate of Southern Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company

* (a) - Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Alabama Power

* (b) - Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Georgia Power

* (c) - Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Gulf Power

* (d) - Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

* (e) - Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Power

* (f) - Certificate of Southern Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(101) XBRL-Related Documents

Southern Company

* INS - XBRL Instance Document

* SCH - XBRL Taxonomy Extension Schema Document

* CAL - XBRL Taxonomy Calculation Linkbase Document

* DEF - XBRL Definition Linkbase Document

* LAB - XBRL Taxonomy Label Linkbase Document

* PRE - XBRL Taxonomy Presentation Linkbase Document

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 110138-EI

EXPLANATION: Provide a copy of the "Business Contracts with Officers, Directors, and Affiliates" schedule included in the company's most recently filed Annual Report as required by Rule 25-6.135, Florida Administrative Code. Provide any subsequent changes affecting the test year.

Type of Data Shown:
___Projected Test Year Ended 12/31/12
___Prior Year Ended 12/31/11
_X_Historical Year Ended 12/31/10
Witness: R. S. Teel

(1) Line No.	(2) Name of Officer or Director	(3) Name and Address of Affiliated Entity	(4) Relationship With Affiliated Entity	(5) Amount of Contract or Transaction	(6) Description of Product or Service
1	See attached schedule. Note the following change for subsequent years:				
2	Fred C. Donovan, Sr. retired, effective August 4, 2010.				

3

Supporting Schedules: Recap Schedules:

Business Contracts with Officers, Directors and Affiliates

Company: Gulf Power Company
For the Year Ended December 31, 2010

List all contracts, agreements, or other business arrangements* entered into during the calendar year (other than compensation-related to position with respondent) between the respondent and each officer and director listed in Part 1 of the Executive Summary. In addition, provide the same information with respect to professional services for each firm, partnership, or organization with which the officer or director is affiliated.

Note * Business agreement, for this schedule, shall mean any oral or written business deal which binds the concerned parties for products or services during the reporting year or future years.

Name of Officer or Director	Name and Address of Affiliated Entity	Amount	Identification of Product or Service
Fred C. Donovan, Sr. Director	Baskerville Donovan Engineers, Inc 449 West Main St. Pensacola, FL 32502	17,195.00	Engineering & Design Services
J. Mort O'Sullivan, III Director	O'Sullivan Creel LLP 316 S. Baylen St., Suite 300 Pensacola, FL 32502	850.00	Accounting Services