MISSISSIPPI POWER COMPANY

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2011 Annual Report

MISSISSIPPI POWER

A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2011 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, 2011.

Edward Day, VI
President and Chief Executive Officer

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer

February 24, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
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 The Southern Company) as of December 31, 2011 and 2010, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such financial statements (pages 32 to 80) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 24, 2012

OVERVIEW

Business Activities

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 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. The Company 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. 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, 2011, 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.

In June 2010, the Mississippi PSC issued a certification of public convenience and necessity (CPCN) authorizing the acquisition, construction, and operation of a new integrated coal gasification combined cycle (IGCC) electric generating plant located in Kemper County, Mississippi (Kemper IGCC), 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.

On October 20, 2011, at the completion of the ten year operating lease, the Company purchased the combined cycle generating Units 3 and 4 at Plant Daniel (Plant Daniel Units 3 and 4) for $84.8 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4. See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein 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 performance 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 2011 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.

The Company was slightly below target for 2011 net income after dividends on preferred stock primarily due to lower retail revenue under PEP and higher interest, net of amounts capitalized, partially offset by lower operations and maintenance expenses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Performance Evaluation Plan" herein for additional information. 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 culture. The 2011 Occupational Safety and Health Administration Incidence Rate was 0.71. The Company is recognized as one of the top in safety performance among all utilities in the Southeastern Electric Exchange. Performance on the Company's culture goals was above target levels for the year.

The Company's 2011 results compared with its targets for some of these key indicators are reflected in the following chart.

Key Performance Indicator	2011 Target Performance	2011 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile overall and in all segments
Peak Season EFOR	4.8% or less	0.68%
Net income after dividends on preferred stock	$98.3 million	$94.2 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2011 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's net income after dividends on preferred stock was $94.2 million in 2011 compared to $80.2 million in 2010. The 17.4% increase in 2011 was primarily the result of increases in allowance for funds used during construction (AFUDC) equity related to the construction of the Kemper IGCC which began in June 2010. This increase in net income after dividends on preferred stock was partially offset by decreases in retail base revenues resulting from closer to normal weather in 2011 compared to 2010 and increased depreciation and amortization. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

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 net income after dividends on preferred stock were partially offset by increases in AFUDC equity, 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.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2011	**2011**	2010
		(in millions)	
Operating revenues	**$ 1,112.9**	**$ (30.2)**	$ (6.3)
Fuel	**490.4**	**(11.4)**	(17.8)
Purchased power	**71.8**	**(11.9)**	(8.3)
Other operations and maintenance	**266.4**	**(1.7)**	21.3
Depreciation and amortization	**80.4**	**3.5**	6.0
Taxes other than income taxes	**70.1**	**0.3**	5.7
Total operating expenses	**979.1**	**(21.2)**	6.9
Operating income	**133.8**	**(9.0)**	(13.2)
Allowance for equity funds used during construction	**24.7**	**20.9**	3.4
Interest income	**1.3**	**1.1**	(0.6)
Interest expense, net of amounts capitalized	**(21.7)**	**0.7**	0.6
Other income (expense), net	**-**	**(3.8)**	1.1
Total other income and (expense)	**4.3**	**18.9**	4.5
Income taxes	**42.2**	**(4.1)**	(3.9)
Net income	**95.9**	**14.0**	(4.8)
Dividends on preferred stock	**1.7**	**-**	-
Net income after dividends on preferred stock	**$ 94.2**	**$ 14.0**	$ (4.8)

Operating Revenues

Details of the Company's operating revenues in 2011 and the prior year were as follows:

	Amount	
	2011	2010
	(in millions)	
Retail – prior year	**$ 797.9**	$ 790.9
Estimated change in –		
Rates and pricing	**0.5**	0.9
Sales growth (decline)	**2.3**	(2.9)
Weather	**(8.9)**	15.0
Fuel and other cost recovery	**0.7**	(6.0)
Retail – current year	**792.5**	797.9
Wholesale revenues –		
Non-affiliates	**273.2**	288.0
Affiliates	**30.4**	41.6
Total wholesale revenues	**303.6**	329.6
Other operating revenues	**16.8**	15.6
Total operating revenues	**$ 1,112.9**	$1,143.1
Percent change	**(2.6)%**	(0.6)%

Total retail revenues for 2011 decreased 0.7% compared to 2010 primarily as a result of lower energy sales due to closer to normal weather in 2011 compared to 2010. Total retail revenues for 2010 increased 0.9% compared to 2009 primarily as a result of higher weather-driven energy sales, partially offset by lower 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 increased in 2011 compared to 2010 primarily as a result of higher recoverable fuel costs. The fuel and other cost recovery revenues decreased in 2010 compared to 2009 primarily as a result of lower recoverable fuel costs, partially offset by an increase in revenues related to ad valorem taxes. 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 fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. 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 sales to non-affiliates decreased $14.8 million, or 5.1%, in 2011 compared to 2010 as a result of a $13.4 million decrease in energy revenues, of which $11.4 million was associated with a decrease in kilowatt-hour (KWH) sales and $2.0 million was associated with lower fuel prices, and a $1.4 million decrease in capacity revenues resulting from the expiration of a power supply agreement in December 2010, partially offset by a wholesale MRA base rate increase effective January 2011. Wholesale revenues from sales to non-affiliates decreased $11.4 million, or 3.8%, in 2010 compared to 2009 as a result of a $21.3 million decrease in energy revenues, of which $5.8 million was associated with lower fuel prices and $15.5 million was associated with a decrease in KWH sales, partially offset by a $9.9 million increase in capacity revenues.

Short-term opportunity energy sales are also included in sales for resale 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.

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 26.9% in 2011 compared to 2010 and decreased 6.6% in 2010 compared to 2009. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues in 2011 increased $1.2 million, or 7.6%, from 2010 primarily due to a $1.8 million increase in transmission revenues. Other operating revenues in 2010 increased $1.0 million, or 6.6%, from 2009 primarily due to a $0.8 million increase in rent from electric property.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2011 and percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2011	**2011**	2010	**2011**	2010
	(in millions)				
Residential	**2,162**	**(5.8)%**	9.8%	**(0.4)%**	(0.3)%
Commercial	**2,871**	**(1.8)**	2.5	**2.1**	(2.1)
Industrial	**4,586**	**2.7**	3.2	**2.7**	3.2
Other	**39**	**0.3**	(0.7)	**0.3**	(0.7)
Total retail	**9,658**	**(0.7)**	4.4	**1.8**	0.7
Wholesale					
Non-affiliated	**4,010**	**(6.4)**	(7.9)		
Affiliated	**649**	**(16.2)**	(7.8)		
Total wholesale	**4,659**	**(7.9)**	(7.9)		
Total energy sales	**14,317**	**(3.1)**	(0.2)%		

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

Residential energy sales decreased 5.8% in 2011 compared to 2010 due to closer to normal weather in 2011 compared to 2010 and a slight decline in the number of residential customers in 2011. 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.

Commercial energy sales decreased 1.8% in 2011 compared to 2010 due to closer to normal weather in 2011 compared to 2010. 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.

Industrial energy sales increased 2.7% in 2011 compared to 2010 due to increased production for many of the industrial customers resulting from an improving economy as well as expansions of some existing customers. 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.

Wholesale energy sales to non-affiliates decreased 6.4% in 2011 compared to 2010 primarily due to decreased KWH sales to rural electric cooperative associations and municipalities located in southeastern Mississippi resulting from closer to normal weather in 2011 compared to 2010. KWH sales to non-affiliates decreased 7.9% in 2010 compared to 2009 primarily due to fewer short-term opportunity sales related to lower gas prices.

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

Wholesale energy sales to affiliates decreased 16.2% in 2011 compared to 2010 primarily due to a decrease in the Company's generation, resulting in less energy available to sell to affiliate companies. Wholesale energy sales to affiliates decreased 7.8% in 2010 compared to 2009 primarily due to an increase in territorial load that was only partially offset by an increase in generation, resulting in less energy available to sell to affiliate 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:

	2011	2010	2009
Total generation *(millions of KWHs)*	**12,986**	13,146	12,970
Total purchased power *(millions of KWHs)*	**2,055**	2,330	2,539
Sources of generation *(percent)* –			
Coal	**40**	51	48
Gas	**60**	49	52
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**4.39**	4.08	4.29
Gas	**3.88**	4.22	4.43
Average cost of fuel, generated *(cents per net KWH)*	**4.10**	4.14	4.36
Average cost of purchased power *(cents per net KWH)*	**3.49**	3.59	3.62

Fuel and purchased power expenses were $562.2 million in 2011, a decrease of $23.3 million, or 4.0%, below the prior year costs. This decrease was primarily due to a $16.5 million decrease related to total KWHs generated and purchased and a $6.8 million decrease in the cost of fuel and purchased power. 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 expense decreased $11.4 million in 2011 compared to 2010. Approximately $4.8 million of the reduction in fuel expenses resulted primarily from lower fuel prices and a $6.6 million decrease in generation from Company-owned facilities. Fuel expense decreased $17.8 million in 2010 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.

Purchased power expense decreased $11.9 million, or 14.2%, in 2011 compared to 2010. The decrease was primarily due to a $2.0 million decrease in the cost of purchased power and a $9.9 million decrease in the amount of energy purchased resulting from higher cost opportunity purchases. Purchased power expense decreased $8.3 million, or 9.0%, in 2010 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. 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 continued to increase in 2011 from the levels experienced in 2010, but remained lower than the unprecedented high levels of 2008. The slowly recovering U.S. economy and global demand from coal importing countries drove the higher prices in 2011, with concerns over regulatory actions, such as permitting issues, and their negative impact on production also contributing upward pressure. Domestic natural gas prices continued to be depressed by robust supplies, including production from shale gas, as well as lower demand. The combination of higher coal prices and lower natural gas prices contributed to increased use of natural gas-fueled generating units in 2011.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery 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 decreased $1.7 million in 2011 compared to 2010 primarily due to a $4.0 million decrease in rent expense resulting from the expiration of the initial term of the Plant Daniel Units 3 and 4 operating lease in October 2011 and a $4.6 million decrease in labor costs. These decreases were partially offset by a $4.2 million increase in generation maintenance expenses for several major outages, a $1.1 million increase in generation-related environmental expenses, and a $2.2 million increase in transmission and distribution expenses related to overhead line maintenance and vegetation maintenance costs. See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.

Total other operations and maintenance expenses increased $21.3 million in 2010 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.

Depreciation and Amortization

Depreciation and amortization increased $3.5 million in 2011 compared to 2010 primarily due to a $5.2 million increase in depreciation resulting from an increase in plant in service and a $1.5 million increase in amortization resulting from the plant acquisition adjustment related to the purchase of Plant Daniel Units 3 and 4, partially offset by a $2.5 million decrease in amortization resulting from the purchase of Plant Daniel Units 3 and 4 and a $0.7 million decrease in Environmental Compliance Overview (ECO) Plan 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 ECO Plan and a $2.7 million increase in depreciation primarily resulting from an increase in plant in service. See Note 1 to the financial statements under "Depreciation and Amortization" and 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 $0.3 million in 2011 compared to 2010 primarily as a result of a $0.9 million increase in franchise taxes and a $0.3 million increase in payroll taxes, partially offset by a $0.9 million decrease in ad valorem 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.

Allowance for Funds Used During Construction Equity

AFUDC equity increased $20.9 million in 2011 as compared to 2010 and $3.4 million in 2010 as compared to 2009. These increases were primarily due to the construction of the Kemper IGCC which began in June 2010. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Interest Income

Interest income increased $1.1 million in 2011 compared to 2010 primarily due to the deferral of carrying costs on the Kemper IGCC regulatory asset. Interest income decreased $0.6 million in 2010 compared to 2009 primarily due to lower interest income related to a regulatory recovery mechanism for fuel and energy cost hedging.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $0.7 million in 2011 compared to 2010 primarily due to a $5.3 million increase in capitalized AFUDC debt associated with the Kemper IGCC, a $1.9 million decrease in interest expense due to deferred interest on the regulatory assets related to Plant Daniel Units 3 and 4 of $1.4 million and the Kemper IGCC of $0.5 million, and a $1.5 million decrease in interest expense resulting from the amortized premium on the assumed debt related to the purchase of Plant Daniel Units 3 and 4. These decreases were partially offset by a $7.9 million increase in interest expense associated with the issuances of new long-term debt in December 2010, April 2011, September 2011, and October 2011. Interest expense, net of amounts capitalized decreased $0.6 million in 2010 compared to 2009 primarily due to a $2.8 million increase in capitalized 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.

Other Income (Expense), Net

Other income (expense), net decreased $3.8 million in 2011 compared to 2010 primarily due to a decrease in amounts collected from customers for contributions in aid of construction. 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.

Income Taxes

Income taxes decreased $4.1 million, or 8.8%, in 2011 compared to 2010 primarily due to an increase in AFUDC equity, which is non-taxable, and an increase in a State of Mississippi manufacturing investment tax credit, partially offset by increased pre-tax income. 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.

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. 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 federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by the Company, and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation to the Company with respect to the Company's Plant Watson. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by the Company) in the U.S. District Court for the Northern District of Alabama.

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

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

Climate Change Litigation

Kivalina Case

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

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2011, the Company had invested approximately $249 million in environmental capital retrofit projects to comply with these requirements, with annual totals of $23 million, $2 million, and $22 million for 2011, 2010, and 2009, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations will be a total of approximately $354 million from 2012 through 2014 as follows:

	2012	2013	2014
		(in millions)	
Existing environmental statutes and regulations	$87	$113	$154

The environmental costs that are known and estimable at this time are included under the heading "Capital" in the table under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. These base environmental costs do not include potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) or the EPA's proposed water and coal combustion byproducts rules, except with respect to $354 million as described below.

The Company is assessing the potential costs of complying with the MATS rule, as well as the EPA's proposed water and coal combustion byproducts rules. See "Air Quality," "Water Quality," and "Coal Combustion Byproducts" below for additional information regarding the MATS rule, the proposed water rules, and the proposed coal combustion byproducts rule. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $1 billion to $2 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is $354 million that is also included in the Company's 2012 through 2014 base level capital investment described herein in anticipation of these rules.

With respect to the impact of the MATS rule on capital spending from 2012 through 2014, the Company's preliminary analysis anticipates that potential incremental environmental compliance capital expenditures to comply with the MATS rule are likely to be substantial and could be up to $430 million from 2012 through 2014. Additionally, capital expenditures to comply with the proposed water and coal combustion byproducts rules could also be substantial and could be up to a total of $121 million over the same 2012 through 2014 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. The estimated costs are as follows:

	2012	2013	2014
		(in millions)	
MATS rule	Up to $30	Up to $100	Up to $300
Proposed water and coal combustion byproducts rules	Up to $1	Up to $30	Up to $90
Total potential incremental environmental compliance investments	**Up to $31**	**Up to $130**	**Up to $390**

The Company's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. These costs may arise from existing unit retirements, installation of additional environmental controls, the addition of new generating resources, upgrades to the transmission system, and changing fuel sources for certain existing units. The Company's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time.

As of December 31, 2011, the Company had total generating capacity of approximately 3,156 MWs, of which 1,450 MWs are coal-fired. As a result of the EPA's final and anticipated rules and regulations, the Company is evaluating its coal-fired generating capacity and is developing a compliance strategy which may include unit retirements, installation of environmental controls, and changing fuel sources for certain units. See "PSC Matters – Environmental Compliance Overview Plan" for information regarding potential construction of a scrubber on Plant Daniel Units 1 and 2.

Compliance with any new federal or state legislation or regulations relating to global climate change, air quality, coal combustion byproducts, water, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company spent approximately $132 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. No area within the Company's service area is currently designated as nonattainment under the current standard. In 2008, the EPA adopted a more stringent eight-hour ozone air quality standard, which it began to implement in September 2011. Based on preliminary 2009-2011 ozone data, the EPA is not expected to designate any nonattainment areas within the Company's service territory, based on this revised standard.

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

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

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

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and NO_x emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. On August 8, 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. Numerous parties (including the Company) sought administrative reconsideration of the CSAPR and also filed appeals and requests to stay the rule pending judicial review with the U.S. Court of Appeals for the District of Columbia Circuit. On December 30, 2011, the U.S. Court of Appeals for the

District of Columbia Circuit stayed the CSAPR in its entirety and ordered the EPA to continue administration of CAIR pending a final decision. Before the stay was granted, the EPA published proposed technical revisions to the CSAPR, including adjustments to certain state emissions budgets and a delay in implementation of the emissions trading limitations until January 2014. On February 7, 2012, the EPA released the final technical revisions to the CSAPR and at the same time issued a direct final rule which together provide increases to certain state emissions budgets, including the State of Mississippi.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. On December 30, 2011, the EPA issued a proposed rule providing that compliance with the CSAPR satisfies BART obligations under the CAVR. Given the pending legal challenge to the CSAPR, it remains uncertain whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 – three years after the effective date of the final rule. As described above, compliance with this rule is likely to require substantial capital expenditures and compliance costs at many of the Company's facilities which could affect unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be affected if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the rule within the compliance period, and the limited compliance period could negatively affect electric system reliability.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, SO_2 and NO_2 standards, the CSAPR, the CAIR, the CAVR, and the MATS rule on the Company cannot be determined at this time and will depend on the specific provisions of the final rules, resolution of pending and future legal challenges, and the development and implementation of rules at the state level. However, these regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

Water Quality

On April 20, 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's existing generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs, as described above, that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the studies conducted in connection with the rulemaking, as well as the specific requirements of the final rule, and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

The Company currently operates two electric generating plants with on-site coal combustion byproducts storage facilities, including both "wet" (ash ponds) and "dry" (landfill) storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Mississippi and Alabama each have has its regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

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

While the ultimate outcome of this matter cannot be determined at this time, and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs, as described above, that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through its ECO clause. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

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

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

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

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

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

The new EPA greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons, based on a company's operational control of facilities. Using the methodology of the rule and based on ownership or financial control of facilities, the Company's 2010 greenhouse gas emissions were approximately 10 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2011 greenhouse gas emissions on the same basis is approximately 10 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

The Company is actively evaluating and developing electric generating technologies with lower greenhouse gas emissions. This includes construction of the Kemper IGCC with approximately 65% carbon capture.

FERC Matters

On November 2, 2011, the Company filed a request with the FERC for revised rates under the wholesale MRA cost-based electric tariff (Tariff). The requested revised rates provide for an increase in annual base wholesale revenues in the amount of approximately \$32 million, effective January 1, 2012. In this filing, the Company is also (i) seeking approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) seeking authorization to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) seeking authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules. On December 29, 2011, the Company received an order from the FERC accepting, but suspending for a nominal period, the proposed rate change and establishing a hearing and settlement procedure if an agreement with the wholesale customers could not be reached. On January 20, 2012, the Company reached a settlement agreement with its wholesale customers, which has been executed by all parties. The settlement agreement is currently under review by the FERC staff. The settlement agreement provides that base rates under the Tariff will increase approximately \$22.6 million over a 12-month period with revised rates to be effective April 1, 2012. In 2012, the amount of base rate revenues to be received from the agreed upon increase will be approximately \$17.0 million. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase is due to a change in the construction work in progress (CWIP) recovery on the Kemper IGCC. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The settlement agreement states that for future rate matters requiring regulatory accounting approval, the Company may follow for accounting and Tariff rate recovery purposes, the treatment allowed by the Mississippi PSC, if such treatment is not in violation of a FERC policy or rule and if agreed to by the wholesale customers. The Tariff customers specifically agreed to the same regulatory treatment for Tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (a) the accounting for Kemper IGCC-related costs that cannot be capitalized, (b) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (c) the establishment of a regulatory asset for certain potential plant retirement costs. The ultimate outcome of this matter cannot be determined at this time.

PSC Matters

Performance Evaluation Plan

In the 2004 order establishing the Company's forward-looking PEP, the Mississippi PSC ordered that the Mississippi Public Utilities Staff (MPUS) 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 2009, concurrent with this review, the annual PEP evaluation filing for 2009 was suspended and the MPUS and the Company filed a joint report with the Mississippi PSC proposing several changes to the PEP. The Mississippi PSC approved the revised PEP in 2009, which resulted in a lower performance incentive under the PEP and therefore smaller and/or less frequent rate changes in the future. Later that year, 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. In November 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 MPUS contested the filing. On June 7, 2011, the Mississippi PSC issued an order approving a joint stipulation between the MPUS and the Company resulting in no change in rates. On November 15, 2011, the Company filed its annual PEP filing for 2012, which indicated a rate increase of 1.893%, or $17.4 million, annually. On January 10, 2012, the MPUS contested the filing. The ultimate outcome of this matter cannot be determined at this time.

In 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, 2011, the Company had fully amortized these costs. See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information regarding the purchase of Plant Daniel Units 3 and 4. In connection with the purchase of Plant Daniel Units 3 and 4, the Company filed a request on July 25, 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized the Company to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into rates over the remaining life of Plant Daniel Units 3 and 4.

On March 15, 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. On May 2, 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. On or before March 15, 2012, the Company will submit its annual PEP lookback filing for 2011. The ultimate outcome of these matters cannot be determined at this time.

Environmental Compliance Overview Plan

On February 14, 2012, the Company submitted its 2012 Environmental Compliance Overview (ECO) Plan notice which proposed a 0.3% increase in annual revenues for the Company. The ultimate outcome of this matter cannot be determined at this time.

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. On April 7, 2011, due to changes in ECO Plan cost projections, the Company submitted a revised 2011 ECO Plan which changed the requested annual revenues to a $0.9 million decrease. On May 5, 2011, the revised ECO Plan filing was approved by the Mississippi PSC with the new rates effective in May 2011.

In February 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, in August 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. In October 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 MPUS 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 decided not to pursue the change in the true-up provision.

In July 2010, the Company filed a request for a CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million. The project is scheduled for completion in late 2015. The Company's portion of the cost, if approved by the Mississippi PSC, is expected to be recovered through the ECO Plan. On May 5, 2011, in conjunction with the ECO Plan approval, the Mississippi PSC approved up to $19.5 million (with respect to the Company's ownership portion) in additional spending for 2011 for the scrubber project. As of December 31, 2011, total project expenditures were $45.6 million, with the Company's portion being $22.8 million. During the Mississippi PSC's open meeting held on January 11, 2012, the Mississippi PSC requested additional information on the scrubber project and updates to the filing have been made. The ultimate outcome of these matters cannot be determined at this time.

On November 10, 2011, the Company filed a request to establish a regulatory asset to defer certain plant retirement costs if such costs are incurred. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. These environmental rules and regulations are continuously being monitored by the Company and all options are being evaluated. On December 6, 2011, an order was granted by the Mississippi PSC authorizing the Company to defer all plant retirement related costs resulting from compliance with environmental regulations as a regulatory asset for future recovery.

Certificated New Plant

On April 27, 2011, the Company 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. As part of the review of the mechanism, the Mississippi PSC will consider costs to be included as well as the allowed rate of return. CNP-A rate filings are made annually. The first filing was made on November 15, 2011 and requested an 11.66% increase in rates, or approximately $98 million annually, to recover these financing costs. If approved by the Mississippi PSC, 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.

On August 9, 2011, the Company submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-B (CNP-B) 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. Under the proposed CNP-B, the Company's allowed cost of capital would be adjusted based on certain operational performance indicators. The ultimate outcome of these matters 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, 2011. On January 6, 2012, a revised filing was made with the Mississippi PSC requesting recovery over an 11 month period. The Mississippi PSC approved the retail fuel cost recovery factor on January 11, 2012, with the new rates effective in February 2012. The retail fuel cost recovery factor will result in an annual decrease in an amount equal to 2.2% of total 2011 retail revenue. At December 31, 2011, the amount of over recovered retail fuel costs included in the balance sheets was $42.4 million compared to $55.2 million at December 31, 2010. The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2012, the wholesale MRA fuel rate decreased, resulting in an annual decrease in an amount equal to 3.0% of total 2011 MRA revenue. Effective February 1, 2012, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 4.3% of total 2011 MB revenue. At December 31, 2011, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $14.3 million and $2.2 million compared to $17.5 million and $4.4 million, respectively, at December 31, 2010. In addition, at December 31, 2011, the amount of over recovered MRA emissions allowance cost included in the balance sheets was $1.7 million. 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.

On March 31, 2011, a portion of the Company's territorial wholesale loads that was formerly served under the MB tariff terminated service. Beginning on April 1, 2011, a new power purchase agreement (PPA) went into effect to cover these MB customers as non-territorial load. On June 21, 2011, the Company and South Mississippi Electric Power Association (SMEPA) reached an agreement to allocate \$3.7 million of the over recovered fuel balance at March 31, 2011 to the PPA. This amount was subsequently refunded to SMEPA on June 27, 2011. See "Other Matters" herein for additional information.

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 2010 audit was completed in the first quarter 2011 with no audit findings. The 2011 audit of fuel-related expenditures began in the second quarter 2011 and was completed in the fourth quarter 2011 with no audit findings.

Income Tax Matters

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013. Due to the significant amount of estimated bonus depreciation for 2012 for Southern Company, tax credit utilization will be reduced, thus eliminating the positive cash flow benefit for the Company.

Integrated Coal Gasification Combined Cycle

The Company is constructing the Kemper IGCC that will utilize an IGCC technology with an output capacity of 582 MWs. In May 2010, the Company filed a motion with the Mississippi PSC accepting the conditions contained in the Mississippi PSC order confirming the Company's application for a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC. In June 2010, the Mississippi PSC issued the CPCN.

The estimated cost of the plant is \$2.4 billion, net of \$245.3 million of grants awarded to the project by the Department of Energy (DOE) under the Clean Coal Power Initiative Round 2 (CCPI2). The Mississippi PSC's order (1) approved a construction cost cap of up to \$2.88 billion (exemptions from the cost cap include the cost of the lignite mine and equipment and the carbon dioxide (CO_2) pipeline facilities), (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 CWIP balances, which provided for the accrual of AFUDC in 2010 and 2011 and provides for the 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. Of the total costs incurred through March 2009, \$46 million has been reviewed and approved by the Mississippi PSC. A decision regarding the remaining \$5 million has been deferred to a later date. The timing of the review of the remaining Kemper IGCC costs is uncertain.

The Kemper IGCC plant, expected to begin commercial operation in May 2014, will use locally mined lignite (an abundant, lower heating value coal) from a mine adjacent to the plant as fuel. In conjunction with the Kemper IGCC, the Company will own the 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 $245 million. In May 2010, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC, a subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operation. The contract with Liberty Fuels is effective June 2010 through the end of the mine reclamation. On December 13, 2011, the Mississippi Department of Environmental Quality (MDEQ) approved the surface coal mining and the water pollution control permits for the mining operation operated by Liberty Fuels. On January 12, 2012, two individuals each filed a notice of appeal and a request for evidentiary hearing with the MDEQ regarding the surface coal mining and water pollution control permits.

In 2009, the Company received notification from the Internal Revenue Service (IRS) formally certifying that the IRS allocated $133 million of Internal Revenue Code of 1986, as amended (Internal Revenue Code) Section 48A tax credits (Phase I) to the Company. On April 19, 2011, the Company received notification from the IRS formally certifying that the IRS allocated $279 million of Internal Revenue Code Section 48A tax credits (Phase II) to the Company. 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 credits, the Company plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the plant during operations in accordance with the recapture rules for Section 48A investment tax credits. Through December 31, 2011, the Company received or accrued tax benefits totaling $99.6 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2011 and 2012, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $77.4 million of these tax credits until after 2012. IRS guidelines allow these unused credits to be carried forward for 20 years expiring at the end of 2031, if not utilized before then.

In 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 and, later in 2008, an agreement was reached to assign the remaining funds ($270 million) to the Kemper IGCC. Through December 31, 2011, the Company has received grant funds of $245.3 million that were used for the construction of the Kemper IGCC. An additional $25 million is expected to be received for its initial operation.

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 for the Kemper IGCC asking for a preliminary and permanent injunction on the issuance of CCPI2 funds and loan guarantees and a stay to any related construction activities based upon alleged deficiencies in the DOE's environmental impact statement. The Company intervened as a party in this lawsuit on May 18, 2011. On November 18, 2011, the U.S. District Court for the District of Columbia denied the Sierra Club's motion for preliminary injunction in the case and dismissed with prejudice the portion of the Sierra Club's claim relating to loan guarantees. On February 2, 2012, the Sierra Club filed for a voluntary dismissal with prejudice of all remaining claims against the DOE pending in the U.S. District Court for the District of Columbia.

In March 2010, the MDEQ issued the Prevention of Significant Deterioration (PSD) air permit modification for the Kemper IGCC, which modifies the original PSD air permit issued in 2008. The Sierra Club requested a formal evidentiary hearing regarding the issuance of the modified permit. On April 4, 2011, the MDEQ Permit Board unanimously affirmed the PSD air permit. On June 30, 2011, the Sierra Club appealed the final PSD air permit issued by the MDEQ to the Chancery Court of Kemper County, Mississippi. The Company has intervened as a party in this appeal.

In June 2010, the Sierra Club filed an appeal of the Mississippi PSC's June 2010 decision to grant the CPCN 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 July 2010, the Company and SMEPA entered into an Asset Purchase Agreement whereby SMEPA agreed to 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. In December 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 4, 2011, the Company and Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., entered into a contract pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC. On May 19, 2011, the Company and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tenrgys, LLC, entered into a contract pursuant to which Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC.

On June 7, 2011, consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities for the Kemper IGCC. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date. In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings.

On September 9, 2011, the Company filed a request for confirmation of the Kemper IGCC's CPCN with the Mississippi PSC authorizing the acquisition, construction, and operation of approximately 61 miles of CO_2 pipeline infrastructure at an estimated capital cost of $141 million. On January 11, 2012, the Mississippi PSC affirmed the confirmation of the Kemper IGCC's CPCN for the acquisition, construction, and operation of the CO_2 pipeline.

As of December 31, 2011, the Company had spent a total of $943.3 million on the Kemper IGCC, including regulatory filing costs. Of this total, $917.8 million was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $21.4 million was recorded in other regulatory assets, $3.1 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed.

See PSC Matters – "Certificated New Plant" herein for information on the proposed rate schedules related to the Kemper IGCC.

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

Other Matters

In 2008, the Company received notice of termination from SMEPA of an approximately 100 MW territorial wholesale market-based contract effective March 31, 2011 which resulted in a decrease in annual base revenues of approximately $12 million. Later in 2008, the Company entered into a 10-year power supply agreement with SMEPA for approximately 152 MWs. This contract was effective April 1, 2011. This contract increased the Company's annual 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 began 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 air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the 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 and financial condition than they would on a non-regulated company.

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

Contingent Obligations

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

Unbilled Revenues

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

Pension and Other Postretirement Benefits

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

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

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.3 million or less change in total benefit expense and a $16.3 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2011. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2012 through 2014, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan remained stable in value as of December 31, 2011. No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012.

Net cash provided from operating activities totaled $231.5 million in 2011 compared to $132.7 million in 2010. The $98.8 million increase in net cash provided from operating activities was primarily due to a $50.6 million decrease in the use of funds related to the Kemper IGCC generation construction screening costs incurred during the first five months of 2010. The Mississippi PSC issued an order in June 2010 approving the Kemper IGCC. Pension, postretirement, and other employee benefits increased by $38.1 million primarily due to a cash payment made in 2010 to fund the qualified pension plan, other accounts payable increased by $36.8 million, and deferred income taxes increased by $34.2 million primarily related to a long-term service agreement (LTSA), bonus depreciation, and fuel cost recovery. Prepaid income taxes increased $30.0 million primarily due to tax refunds related to 2010 investment tax credits received in 2011. These increases in cash provided from operating activities were partially offset by a $45.0 million decrease in over recovered regulatory clause revenues related to lower fuel rates in 2011 and 2010 and a decrease in fossil fuel stock of $42.9 million primarily due to increases in coal and coal in transit. 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 were partially offset by an increase in deferred income taxes of $77.4 million primarily related to a LTSA, bonus depreciation, and an increase in investment tax credits of $22.2 million related to the Kemper IGCC.

Net cash used for investing activities totaled $682.7 million for 2011 compared to $254.4 million for 2010. The $428.3 million increase was primarily due to an increase in property additions of $717.2 million primarily related to the Kemper IGCC and an increase in plant acquisition of $84.8 million due to the cash payment associated with the purchase of Plant Daniel Units 3 and 4. These increases in cash used for investing activities were partially offset by a construction payable increase of $63.3 million, a $100.0 million change in restricted cash associated with the second series revenue bonds issued in December 2010, and an increase of $208.8 million in capital grant proceeds received primarily related to CCPI2 and Smart Grid Investment grants. 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" herein for additional information.

Net cash provided from financing activities totaled $502.0 million in 2011 compared to $217.5 million in 2010. The $284.5 million increase in net cash provided from financing activities was primarily due to a $234.1 million increase in capital contributions from Southern Company, a $190.0 million increase in long-term debt, and a $130 million redemption of long-term debt. 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.

Significant changes in the balance sheet as of December 31, 2011 compared to 2010 include an increase in total property, plant, and equipment of $1.1 billion primarily due to the increase in construction work in progress related to the Kemper IGCC and an increase in plant in service related to the purchase of Plant Daniel Units 3 and 4. Other accounts payable increased $109.0 million primarily due to increases in construction projects. Long-term debt increased $641.6 million primarily due to the assumption of $270.0 million taxable revenue bonds in October 2011 and the issuance of $300.0 million of senior notes in October 2011. Accumulated deferred investment tax credits increased $76.1 million primarily related to the Kemper IGCC. Common stockholder's equity increased $311.8 million primarily due to the increase in paid-in capital due to $300.0 million in capital contributions from Southern Company in 2011.

The Company's ratio of common equity to total capitalization, excluding long-term debt due within one year, decreased from 59.8% in 2010 to 48.0% at December 31, 2011.

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. In 2011, the Company received $300 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.

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. There can be no assurance that the DOE will issue federal loan guarantees to the Company. Through December 31, 2011, the Company has received $245.3 million in DOE CCPI2 grant funds that were used for the construction of the Kemper IGCC. An additional $25 million in CCPI2 grant funds is expected to be received for the initial operation of the Kemper IGCC.

Investment tax credits related to the Kemper IGCC of $77.4 million are not expected to be utilized until after 2012, which could result in additional financing needs. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

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. 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.

At December 31, 2011, the Company had approximately $211.6 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2011 were as follows:

Expires[a]				Executable Term-Loans	
				One	Two
2012	2014	Total	Unused	Year	Years
			(in millions)		
$131	$165	$296	$296	$25	$41

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

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

Most of these arrangements contain covenants that limit debt levels and typically contain cross-default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. The Company is currently in compliance with all such covenants.

These credit arrangements provide liquidity support to the Company's variable rate tax-exempt pollution control revenue bonds and commercial paper borrowings. At December 31, 2011, the Company had $40.1 million of outstanding pollution control revenue bonds requiring liquidity support.

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

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$-	-%	$ 7	0.21%	$70
December 31, 2010:					
Commercial paper	$-	-%	$ 12	0.28%	$63

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

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

In February 2011, the Company redeemed a $50 million series of revenue bonds issued in December 2010.

In March 2011, the Company's $80 million long-term bank note with a variable interest rate based on one-month London Interbank Offered Rate (LIBOR) matured.

In April 2011, the Company 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 the Company's continuous construction program.

In September 2011, the Company entered into a one-year $40 million aggregate principal amount floating rate bank loan that bears interest based on one-month LIBOR. The proceeds were used to repay outstanding short-term debt and for general corporate purposes, including the Company's continuous construction program. In addition, the Company entered into a one-year extension of a $125 million aggregate principal amount floating rate bank loan that bears interest based on one-month LIBOR.

In September 2011, the Company entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to anticipated debt issuances. The notional amount of the swaps totaled $600 million. The Company settled $300 million of the interest rate swaps in October 2011; $150 million related to its Series 2011A 2.35% Senior Note issuance at a gain of approximately $1.4 million which will be amortized to interest expense, in earnings, over five years and $150 million related to its Series 2011B 4.75% Senior Note issuance at a loss of approximately $0.5 million which will be amortized to interest expense, in earnings, over 10 years.

In October 2011, the Company issued $150 million aggregate principal amount of Series 2011A 2.35% Senior Notes due October 15, 2016 and $150 million aggregate principal amount of Series 2011B 4.75% Senior Notes due October 15, 2041. The net proceeds were used by the Company to pay amounts in connection with the purchase of Plant Daniel Units 3 and 4 as described herein under "Purchase of the Plant Daniel Combined Cycle Generating Units," and for general corporate purposes, including the Company's continuous construction program.

In October 2011, the Company assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor as described under "Purchase of the Plant Daniel Combined Cycle Generating Units" herein. These bonds are secured by Plant Daniel Units 3 and 4 and certain personal property. The bonds have been recorded on the financial statements at the fair value of the debt on the date of assumption, or $346.1 million, reflecting a premium of $76.1 million.

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.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, the Company began an initial 10-year term of an operating lease agreement for Plant Daniel Units 3 and 4. The Company was required to provide notice of its intent to either renew the lease or purchase Plant Daniel Units 3 and 4 by July 22, 2011. On July 20, 2011, the Company provided notice to the lessor of its intent to purchase Plant Daniel Units 3 and 4. The Company's right to purchase Plant Daniel Units 3 and 4 was approved by the Mississippi PSC in its order dated January 7, 1998, as amended on February 19, 1999, which granted the Company a CPCN for Plant Daniel Units 3 and 4.

On October 20, 2011, the Company purchased Plant Daniel Units 3 and 4 for $84.8 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on the Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was $346.1 million. The fair value of the debt was determined using a discounted cash flow model based on the Company's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. See Note 1 to the financial statements under "Purchase of the Plant Daniel Combined Cycle Generating Units" for additional information regarding the debt valuation. Accordingly, Plant Daniel Units 3 and 4 are reflected in the Company's financial statements at $430.9 million.

In connection with the purchase of Plant Daniel Units 3 and 4, the Company filed a request on July 25, 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized the Company to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into rates over the remaining life of Plant Daniel Units 3 and 4. On November 2, 2011, the Company filed a request with the FERC seeking the same accounting and regulatory treatment for its wholesale cost-based jurisdiction. The ultimate outcome of this matter cannot be determined at this time.

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, 2011, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $330 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, 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.

To mitigate future exposure changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $280 million of outstanding variable rate long-term debt at December 31, 2011 was 0.63%. 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 $2.8 million at December 31, 2011. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts or heat-rate contracts for the purchase and sale of electricity through the wholesale electricity market. At December 31, 2011, 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, 2011, exposure from these activities was not material to the Company's financial statements.

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

	2011 Changes	2010 Changes
	Fair Value	
	(in thousands)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$(43,770)**	$(41,734)
Contracts realized or settled	**32,381**	32,853
Current period changes[a]	**(39,601)**	(34,889)
Contracts outstanding at the end of the period, assets (liabilities), net	**$(50,990)**	$(43,770)

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

The change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2011 was a decrease of $7.2 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2011, the Company had a net hedge volume of 31.0 million mmBtu with a weighted average swap contract cost of approximately $1.98 per mmBtu above market prices, and a net hedge volume of 24.0 million mmBtu at December 31, 2010 with a weighted average swap contract cost of approximately $1.92 per mmBtu above market prices. The majority of the costs associated with natural gas hedges are recovered through the Company's ECM clause.

At December 31, 2011 and 2010, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the 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 2012.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2011 were as follows:

	Fair Value Measurements December 31, 2011			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in thousands)		
Level 1	**$** -	$ -	$ -	$ -
Level 2	50,990	36,330	14,371	289
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$ 50,990	$ 36,330	$ 14,371	$ 289

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

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

Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. Included in the estimated base level capital investment amounts are expenditures related to the Kemper IGCC of $1.3 billion, $124 million, and $74 million in 2012, 2013, and 2014, respectively, which are net of SMEPA's 17.5% expected ownership share of the Kemper IGCC of approximately $466 million and $16 million in 2013 and 2014, respectively. These estimated base level capital investment amounts also include capital expenditures covered under LTSAs. Potential incremental environmental compliance investments to comply with the MATS rule and with the proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment, except as described below. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $1 billion to $2 billion through 2021 based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is $354 million that is also included in the Company's 2012 through 2014 base level capital investment described herein in anticipation of these rules. The Company's base level construction program and the potential incremental environmental compliance investments for the MATS rule and the proposed water and coal combustion byproducts rules over the next three years, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2012	2013	2014
Construction program:		*(in millions)*	
Base capital	$1,409	$250	$ 198
Existing environmental statutes and regulations	87	113	154
Total construction program base level capital investment	**$1,496**	**$363**	**$ 352**
Potential incremental environmental compliance investments:			
MATS rule	Up to $30	Up to $100	Up to$300
Proposed water and coal combustion byproducts rules	Up to $1	Up to $30	Up to $90
Total potential incremental environmental compliance investments	**Up to $31**	**Up to $130**	**Up to $390**

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; 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. 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, 2, 5, 6, 7, and 10 to the financial statements for additional information.

Contractual Obligations

	2012	2013-2014	2015-2016	After 2016	Uncertain Timing [d]	Total
			(in thousands)			
Long-term debt[a] –						
Principal	$ 240,000	$ 50,000	$ 150,000	$832,695	$ -	$1,272,695
Interest	53,580	100,680	97,680	467,682	-	719,622
Preferred stock dividends[b]	1,733	3,465	3,465	-	-	8,663
Energy-related derivative obligations[c]	36,455	14,372	325	-	-	51,152
Foreign currency derivative obligations[c]	2,464	46	-	-	-	2,510
Interest rate derivative obligations[c]	15,208	-	-	-	-	15,208
Unrecognized tax benefits and interest[d]	3,349	-	-	-	2,295	5,644
Operating leases [e]	11,870	20,984	2,087	523	-	35,464
Capital leases[f]	633	-	-	-	-	633
Purchase commitments[g] –						
Capital[h]	1,495,583	683,013	-	-	-	2,178,596
Coal	267,075	58,205	1,920	35,520	-	362,720
Natural gas[i]	159,394	265,426	181,486	146,169	-	752,475
Long-term service agreements[j]	14,123	29,287	30,212	30,264	-	103,886
Pension and other postretirement benefits plans[k]	5,232	11,288	-	-	-	16,520
Total	$2,306,699	$1,236,766	$ 467,175	$1,512,853	$2,295	$5,525,788

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2012, as reflected in the statements of capitalization. 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 $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.
(e) 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 2011, 2010, and 2009 were $266 million, $268 million, and $247 million, respectively.
(h) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to capital expenditures covered under long-term service agreements. In addition, such amounts exclude the Company's estimates of other potential incremental environmental compliance investments to comply with the MATS rule and the proposed water and coal combustion byproducts rules which are likely to be substantial and could be up to $31 million, up to $130 million, and up to $390 million for 2012, 2013, and 2014, respectively. 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, 2011, 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, 2011.
(j) Long-term service agreements include price escalation based on inflation indices.
(k) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2011 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, storm damage cost recovery and repairs, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan, financing activities, start and completion of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, the pending EPA civil action, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to the Kemper IGCC, including Mississippi PSC approvals, potential DOE loan guarantees, the SMEPA purchase decision, and utilization of investment tax credits;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME

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

Mississippi Power Company 2011 Annual Report

	2011	2010	2009
		(in thousands)	
Operating Revenues:			
Retail revenues	**$792,463**	$797,912	$790,950
Wholesale revenues, non-affiliates	**273,178**	287,917	299,268
Wholesale revenues, affiliates	**30,417**	41,614	44,546
Other revenues	**16,819**	15,625	14,657
Total operating revenues	**1,112,877**	1,143,068	1,149,421
Operating Expenses:			
Fuel	**490,415**	501,830	519,687
Purchased power, non-affiliates	**6,239**	8,426	8,831
Purchased power, affiliates	**65,574**	75,230	83,104
Other operations and maintenance	**266,395**	268,063	246,758
Depreciation and amortization	**80,337**	76,891	70,916
Taxes other than income taxes	**70,127**	69,810	64,068
Total operating expenses	**979,087**	1,000,250	993,364
Operating Income	**133,790**	142,818	156,057
Other Income and (Expense):			
Allowance for equity funds used during construction	**24,707**	3,795	387
Interest income	**1,347**	215	804
Interest expense, net of amounts capitalized	**(21,691)**	(22,341)	(22,940)
Other income (expense), net	**(45)**	3,738	2,606
Total other income and (expense)	**4,318**	(14,593)	(19,143)
Earnings Before Income Taxes	**138,108**	128,225	136,914
Income taxes	**42,193**	46,275	50,214
Net Income	**95,915**	81,950	86,700
Dividends on Preferred Stock	**1,733**	1,733	1,733
Net Income After Dividends on Preferred Stock	**$ 94,182**	$ 80,217	$ 84,967

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

STATEMENTS OF COMPREHENSIVE INCOME

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

Mississippi Power Company 2011 Annual Report

	2011	2010	2009
		(in thousands)	
Net Income After Dividends on Preferred Stock	**$94,182**	$80,217	$84,967
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(5,494), $1, and $-, respectively	**(8,870)**	2	-
Reclassification adjustment for amounts included in net income, $(18), $-, and $-, respectively	**(29)**	-	-
Total other comprehensive income (loss)	**(8,899)**	2	-
Comprehensive Income	**$85,283**	$80,219	$84,967

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

STATEMENTS OF CASH FLOWS

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

Mississippi Power Company 2011 Annual Report

	2011	2010	2009
		(in thousands)	
Operating Activities:			
Net income	**$ 95,915**	$ 81,950	$ 86,700
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**83,787**	82,294	78,914
Deferred income taxes	**71,764**	37,557	(39,849)
Investment tax credits received	**-**	22,173	-
Allowance for equity funds used during construction	**(24,707)**	(3,795)	(387)
Pension, postretirement, and other employee benefits	**3,169**	(34,911)	7,077
Hedge settlements	**848**	-	-
Stock based compensation expense	**1,548**	1,186	886
Generation construction screening costs	**-**	(50,554)	(30,638)
Other, net	**(8,151)**	(3,404)	(3,229)
Changes in certain current assets and liabilities --			
-Receivables	**5,864**	(8,185)	9,677
-Under recovered regulatory clause revenues	**-**	-	54,994
-Fossil fuel stock	**(27,933)**	14,997	(41,699)
-Materials and supplies	**(2,116)**	(879)	(649)
-Prepaid income taxes	**12,907**	(17,075)	1,061
-Other current assets	**1,606**	(4,633)	2,065
-Other accounts payable	**24,143**	(12,630)	(7,590)
-Accrued taxes	**1,209**	(4,268)	8,800
-Accrued compensation	**(187)**	2,291	(6,819)
-Over recovered regulatory clause revenues	**(16,544)**	28,450	48,596
-Other current liabilities	**8,373**	2,137	2,732
Net cash provided from operating activities	**231,495**	132,701	170,642
Investing Activities:			
Property additions	**(964,233)**	(247,005)	(101,995)
Plant acquisition	**(84,803)**	-	-
Investment in restricted cash	**-**	(50,000)	-
Distribution of restricted cash	**50,000**	-	-
Cost of removal net of salvage	**(7,432)**	(9,240)	(9,352)
Construction payables	**97,079**	33,767	(5,091)
Capital grant proceeds	**232,442**	23,657	-
Other investing activities	**(5,736)**	(5,587)	(2,971)
Net cash used for investing activities	**(682,683)**	(254,408)	(119,409)
Financing Activities:			
Decrease in notes payable, net	**-**	-	(26,293)
Proceeds --			
Capital contributions from parent company	**299,305**	65,215	4,567
Senior notes issuances	**300,000**	-	125,000
Other long-term debt issuances	**115,000**	225,000	-
Redemptions --			
Capital leases	**(1,437)**	(1,330)	-
Senior notes	**-**	-	(40,000)
Other long-term debt	**(130,000)**	-	-
Payment of preferred stock dividends	**(1,733)**	(1,733)	(1,733)
Payment of common stock dividends	**(75,500)**	(68,600)	(68,500)
Other financing activities	**(3,641)**	(1,091)	(1,662)
Net cash provided from (used for) financing activities	**501,994**	217,461	(8,621)
Net Change in Cash and Cash Equivalents	**50,806**	95,754	42,612
Cash and Cash Equivalents at Beginning of Year	**160,779**	65,025	22,413
Cash and Cash Equivalents at End of Year	**$211,585**	$160,779	$ 65,025
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $10,065, $2,903 and $117 capitalized, respectively)	**$14,814**	$19,518	$19,832
Income taxes (net of refunds)	**(41,024)**	7,546	77,206
Noncash transactions - accrued property additions at year-end	**135,902**	37,736	3,689
Assumption of debt due to plant acquisition	**346,051**	-	-

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

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

Assets	2011	2010
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 211,585**	$ 160,779
Restricted cash	**-**	50,000
Receivables --		
Customer accounts receivable	**32,551**	37,532
Unbilled revenues	**27,239**	31,010
Other accounts and notes receivable	**7,080**	11,220
Affiliated companies	**23,078**	17,837
Accumulated provision for uncollectible accounts	**(547)**	(638)
Fossil fuel stock, at average cost	**140,173**	112,240
Materials and supplies, at average cost	**30,787**	28,671
Other regulatory assets, current	**69,201**	63,896
Prepaid income taxes	**37,793**	59,596
Other current assets	**8,881**	19,057
Total current assets	**587,821**	591,200
Property, Plant, and Equipment:		
In service	**2,902,240**	2,392,477
Less accumulated provision for depreciation	**1,019,251**	971,559
Plant in service, net of depreciation	**1,882,989**	1,420,918
Construction work in progress	**955,135**	274,585
Total property, plant, and equipment	**2,838,124**	1,695,503
Other Property and Investments	**6,520**	5,900
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**25,009**	18,065
Other regulatory assets, deferred	**185,694**	132,420
Other deferred charges and assets	**28,674**	33,233
Total deferred charges and other assets	**239,377**	183,718
Total Assets	**$3,671,842**	$2,476,321

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

Liabilities and Stockholder's Equity	2011	2010
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 240,633**	$ 256,437
Accounts payable --		
Affiliated	**62,650**	51,887
Other	**168,309**	59,295
Customer deposits	**13,658**	12,543
Accrued taxes --		
Accrued income taxes	**3,813**	4,356
Other accrued taxes	**53,825**	51,709
Accrued interest	**12,750**	5,933
Accrued compensation	**15,889**	16,076
Other regulatory liabilities, current	**5,779**	6,177
Over recovered regulatory clause liabilities	**60,502**	77,046
Liabilities from risk management activities	**54,127**	27,525
Other current liabilities	**17,533**	20,115
Total current liabilities	**709,468**	589,099
Long-Term Debt (See accompanying statements)	**1,103,596**	462,032
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**270,397**	281,967
Deferred credits related to income taxes	**11,058**	11,792
Accumulated deferred investment tax credits	**109,761**	33,678
Employee benefit obligations	**161,065**	113,964
Other cost of removal obligations	**126,424**	111,614
Other regulatory liabilities, deferred	**60,848**	58,814
Other deferred credits and liabilities	**37,228**	43,213
Total deferred credits and other liabilities	**776,781**	655,042
Total Liabilities	**2,589,845**	1,706,173
Cumulative Redeemable Preferred Stock (See accompanying statements)	**32,780**	32,780
Common Stockholder's Equity (See accompanying statements)	**1,049,217**	737,368
Total Liabilities and Stockholder's Equity	**$3,671,842**	$2,476,321
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION

At December 31, 2011 and 2010

Mississippi Power Company 2011 Annual Report

	2011	2010	**2011**	2010
		(in thousands)		*(percent of total)*
Long-Term Debt:				
Long-term notes payable --				
6.00% due 2013	**50,000**	50,000		
2.35% due 2016	**150,000**	-		
2.25% to 5.625% due 2017-2041	**480,000**	330,000		
Adjustable rates (0.56% to 0.71% at 1/1/11) due 2011	**-**	205,000		
Adjustable rates (0.60% to 0.85% at 1/1/12) due 2012	**240,000**	-		
Adjustable rates (0.44% at 1/1/11) due 2040	**-**	50,000		
Total long-term notes payable	**920,000**	635,000		
Other long-term debt --				
Pollution control revenue bonds:				
5.15% due 2028	**42,625**	42,625		
Variable rates (0.08% to 0.16% at 1/1/12) due 2020-2028	**40,070**	40,070		
Plant Daniel revenue bonds (7.13%) due 2021	**270,000**	-		
Total other long-term debt	**352,695**	82,695		
Capitalized lease obligations	**633**	2,070		
Unamortized debt premium (related to plant acquisition)	**74,551**	-		
Unamortized debt discount	**(3,650)**	(1,296)		
Total long-term debt (annual interest requirement -- $53.6 million)	**1,344,229**	718,469		
Less amount due within one year	**240,633**	256,437		
Long-term debt excluding amount due within one year	**1,103,596**	462,032	**50.5%**	37.5%
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	**1.5**	2.7
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	**694,855**	392,790		
Retained earnings	**325,568**	306,885		
Accumulated other comprehensive income (loss)	**(8,897)**	2		
Total common stockholder's equity	**1,049,217**	737,368	**48.0**	59.8
Total Capitalization	**$2,185,593**	$1,232,180	**100.0%**	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2011, 2010, and 2009
Mississippi Power Company 2011 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2008	1,121	$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
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**
Net income after dividends on preferred stock	**-**	**-**	**-**	**94,182**	**-**	**94,182**
Capital contributions from parent company	**-**	**-**	**302,065**	**-**	**-**	**302,065**
Other comprehensive income (loss)	**-**	**-**	**-**	**-**	**(8,899)**	**(8,899)**
Cash dividends on common stock	**-**	**-**	**-**	**(75,500)**	**-**	**(75,500)**
Other	**-**	**-**	**-**	**1**	**-**	**1**
Balance at December 31, 2011	**1,121**	**$37,691**	**$694,855**	**$325,568**	**$(8,897)**	**$1,049,217**

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

The equity method is used for entities in which the Company has significant influence but does not control 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 $185.5 million, $125.1 million, and $84.0 million during 2011, 2010, and 2009, respectively. The increase in 2011 SCS costs is primarily due to the construction of the new integrated coal gasification combined cycle (IGCC) electric generating plant located in Kemper County, Mississippi (Kemper IGCC) and large environmental projects. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies. The Company also provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount.

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, which totaled $12.2 million, $11.2 million, and $10.2 million in 2011, 2010, and 2009, 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, which totaled $23.3 million, $25.0 million, and $20.9 million in 2011, 2010, and 2009, respectively. See Note 4 for additional information.

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

Regulatory Assets and Liabilities

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

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

	2011	2010	Note
	(in thousands)		
Hurricane Katrina	**$ -**	$ (143)	(a)
Retiree benefit plans	**130,678**	86,748	(b,k)
Property damage	**(64,748)**	(61,171)	(m)
Deferred income tax charges	**21,000**	13,654	(d)
Property tax	**18,484**	18,649	(e)
Transmission & distribution deferral	**-**	2,367	(f)
Vacation pay	**9,128**	9,143	(g,k)
Loss on reacquired debt	**7,171**	7,775	(h)
Loss on redeemed preferred stock	**-**	57	(i)
Loss on rail cars	**-**	8	(h)
Plant Daniel Units 3 and 4 regulatory assets	**3,945**	-	(o)
Other regulatory assets	**132**	-	(c)
Fuel-hedging (realized and unrealized) losses	**54,103**	48,729	(j,k)
Asset retirement obligations	**9,057**	9,302	(d)
Deferred income tax credits	**(12,081)**	(13,189)	(d)
Other cost of removal obligations	**(126,424)**	(111,614)	(d)
Fuel-hedging (realized and unrealized) gains	**(162)**	(2,067)	(j,k)
Kemper IGCC regulatory assets	**20,684**	12,295	(l)
Other liabilities	**(693)**	(81)	(c)
Deferred income tax charges – Medicare subsidy	**5,521**	5,521	(n)
Total assets (liabilities), net	**$ 75,795**	$ 25,983	

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.
(d) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred 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 2012, 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.
(o) Recovered and amortized over a 10-year period ending October 2021, as approved by the Mississippi PSC for the difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term. See Note 3 under "Retail Regulatory Matters – Performance Evaluation Plan" for additional information.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

Government Grants

In 2008, the Company requested that the Department of Energy (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 August 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270 million of the Kemper IGCC through the CCPI2 funds. Through December 31, 2011, the Company has received grant funds of $245.3 million, used for the construction of the Kemper IGCC, which is reflected in the Company's financial statements as a reduction to the Kemper IGCC capital costs. An additional $25 million is expected to be received for its initial operation.

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 generally includes fuel transportation costs and 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 any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction for projects over $1 million where recovery of construction work in progress is not allowed in rates.

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

	2011	2010
	(in thousands)	
Generation	**$ 1,362,567**	$ 990,151
Transmission	**497,202**	464,716
Distribution	**784,655**	765,578
General	**176,408**	172,032
Plant acquisition adjustment	**81,408**	-
Total plant in service	**$ 2,902,240**	$ 2,392,477

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.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, the Company began the initial 10-year term of an operating lease agreement for combined cycle generating units 3 and 4 built at Plant Daniel (Plant Daniel Units 3 and 4). On July 20, 2011, the Company provided notice to the lessor of its intent to purchase Plant Daniel Units 3 and 4. The Company's right to purchase Plant Daniel Units 3 and 4 was approved by the Mississippi PSC in its order dated January 7, 1998, as amended on February 19, 1999, which granted the Company a Certificate of Public Convenience and Necessity (CPCN) for Plant Daniel Units 3 and 4.

On October 20, 2011, the Company purchased Plant Daniel Units 3 and 4 for $84.8 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on the Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was $346.1 million. The fair value of the debt was determined using a discounted cash flow model based on the Company's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. Accordingly, Plant Daniel Units 3 and 4 are reflected in the Company's financial statements as follows:

Assumption of debt obligations	$ 270,000
Fair value adjustment at date of purchase	76,051
Total debt	346,051
Cash payment for the purchase	84,803
Total value of Plant Daniel Units 3 and 4	$ 430,854

See Note 3 under "Retail Regulatory Matters – Performance Evaluation Plan" for additional information.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.9% in 2011, 3.4% in 2010, and 3.3% in 2009. 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 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 2009. In April 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.

The Company, in compliance with FERC guidance, classified $81.4 million as a plant acquisition adjustment on the purchase of Plant Daniel Units 3 and 4. This includes $76.1 million recorded in conjunction with the premium on long-term debt and will be amortized over 10 years beginning October 2011. See "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.

On January 11, 2012, the Mississippi PSC issued an order allowing the Company to defer in a regulatory asset the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 and the revenue requirement assuming operating lease accounting treatment for the extended term. The regulatory asset will be deferred for a 10-year period ending October 2021. At the conclusion of the deferral period, the unamortized deferral balance will be amortized into rates over the remaining life of the units.

In 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, 2011, the Company had fully amortized these costs.

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, deep injection wells, water wells, substation removal, generator removal, 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 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:

	2011	2010
	(in thousands)	
Balance at beginning of year	$ 18,601	$ 17,431
Liabilities incurred	137	(1)
Liabilities settled	(644)	155
Accretion	1,054	1,016
Cash flow revisions	-	-
Balance at end of year	$ 19,148	$ 18,601

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 7.06%, 7.33%, and 7.92% for the years ended December 31, 2011, 2010, and 2009, 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 31.60%, 6.97%, and 0.5% for 2011, 2010, and 2009, respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the 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. In January 2009, the Mississippi PSC approved the System Restoration Rider (SRR) stipulation between the Company and the Mississippi Public Utilities Staff (MPUS). In accordance with the stipulation, every three years the Mississippi PSC, MPUS, 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 MPUS 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 2011, 2010, and 2009, the Company made retail accruals of $3.8 million, $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 – System Restoration Rider" for additional information. The Company accrued $0.3 million annually in 2011, 2010 and in 2009 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.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, and emissions allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates. The retail rate is approved by the Mississippi PSC while the wholesale rates are filed with the FERC. 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, 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. Fuel and interest rate 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. Foreign currency exchange rate hedges are designated as fair value hedges. Settled hedges are booked as construction work in progress (CWIP). Any ineffectiveness arising from these would be recognized currently in net income; however, the Company has regulatory approval allowing it to defer any ineffectiveness arising from hedging program instruments relating to the Kemper IGCC to a regulatory asset. 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, 2011.

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

The Company is required to provide financing for all costs associated with the mine development and operation under a contract with Liberty Fuels Company, LLC, a subsidiary of North American Coal Corporation (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. For the years ended 2011 and 2010, Liberty Fuels did not have a material impact on the financial position and results of operations of the Company. See Note 3 under "Integrated Coal Gasification Combined Cycle" 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). No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2012, other postretirement trust contributions are expected to be less than $1 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2008 for the 2009 plan year using a discount rate of 6.75% and an annual salary increase of 3.75%.

	2011	2010	2009
Discount rate:			
Pension plans	**4.98%**	5.51%	5.92%
Other postretirement benefit plans	**4.87**	5.39	5.83
Annual salary increase	**3.84**	3.84	4.18
Long-term return on plan assets:			
Pension plans*	**8.45**	8.45	8.20
Other postretirement benefit plans	**7.53**	7.65	7.62

* Net of estimated investment management expenses of 30 basis points.

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2011 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2019
Post-65 medical	6.00	5.00	2019
Post-65 prescription	6.00	5.00	2023

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2011 as follows:

	1 Percent Increase	1Percent Decrease
	(in thousands)	
Benefit obligation	$ 6,062	$(5,156)
Service and interest costs	365	(310)

Pension Plans

The total accumulated benefit obligation for the pension plans was $339 million at December 31, 2011 and $307 million at December 31, 2010. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$330,315**	$309,179
Service cost	**8,838**	8,300
Interest cost	**17,827**	17,916
Benefits paid	**(14,587)**	(12,206)
Plan amendments	**-**	48
Actuarial loss (gain)	**27,287**	7,078
Balance at end of year	**369,680**	330,315
Change in plan assets		
Fair value of plan assets at beginning of year	**283,698**	218,015
Actual return (loss) on plan assets	**10,805**	33,780
Employer contributions	**2,184**	44,109
Benefits paid	**(14,587)**	(12,206)
Fair value of plan assets at end of year	**282,100**	283,698
Accrued liability	**$ (87,580)**	$ (46,617)

At December 31, 2011, the projected benefit obligations for the qualified and non-qualified pension plans were $344 million and $26 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's pension plans consist of the following:

	2011	2010
	(in thousands)	
Other regulatory assets, deferred	**$ 117,354**	$ 78,130
Other current liabilities	**(1,652)**	(1,516)
Employee benefit obligations	**(85,928)**	(45,101)

Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2012.

	2011	2010	**Estimated Amortization in 2012**
		(in thousands)	
Prior service cost	**$ 6,570**	$ 7,879	**$ 1,309**
Net (gain) loss	**110,784**	70,251	**4,100**
Other regulatory assets, deferred	**$ 117,354**	$ 78,130	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets
	(in thousands)
Balance at December 31, 2009	$ 85,357
Net (gain) loss	(5,250)
Change in prior service costs	48
Reclassification adjustments:	
Amortization of prior service costs	(1,391)
Amortization of net gain (loss)	(634)
Total reclassification adjustments	(2,025)
Total change	(7,227)
Balance at December 31, 2010	$ 78,130
Net (gain) loss	**41,647**
Change in prior service costs	-
Reclassification adjustments:	
Amortization of prior service costs	**(1,309)**
Amortization of net gain (loss)	**(1,114)**
Total reclassification adjustments	**(2,423)**
Total change	**39,224**
Balance at December 31, 2011	**$ 117,354**

Components of net periodic pension cost were as follows:

	2011	2010	2009
		(in thousands)	
Service cost	**$ 8,838**	$ 8,300	$6,792
Interest cost	**17,827**	17,916	17,577
Expected return on plan assets	**(25,166)**	(21,451)	(21,065)
Recognized net (gain) loss	**1,114**	634	539
Net amortization	**1,309**	1,391	1,578
Net periodic pension cost	**$ 3,922**	$ 6,790	$ 5,421

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2011, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2012	$15,125
2013	15,892
2014	16,722
2015	17,528
2016	18,457
2017 to 2021	109,185

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 81,688**	$ 83,774
Service cost	**1,012**	1,305
Interest cost	**4,292**	4,763
Benefits paid	**(4,094)**	(4,245)
Actuarial loss (gain)	**4,073**	(2,511)
Plan amendments	**-**	(1,824)
Retiree drug subsidy	**476**	426
Balance at end of year	**87,447**	81,688
Change in plan assets		
Fair value of plan assets at beginning of year	**20,955**	20,292
Actual return (loss) on plan assets	**720**	2,297
Employer contributions	**2,477**	2,185
Benefits paid	**(3,618)**	(3,819)
Fair value of plan assets at end of year	**20,534**	20,955
Accrued liability	**$ (66,913)**	$(60,733)

Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's other postretirement benefit plans consist of the following:

	2011	2010
	(in thousands)	
Other regulatory assets, deferred	**$ 13,324**	$ 8,618
Employee benefit obligations	**(66,913)**	(60,733)

Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2012.

	2011	2010	**Estimated Amortization in 2012**
		(in thousands)	
Prior service cost	**$ (2,686)**	$ (2,873)	**$ (188)**
Net (gain) loss	**15,839**	11,092	**487**
Transition obligation	**171**	399	**171**
Other regulatory assets, deferred	**$ 13,324**	$ 8,618	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets
	(in thousands)
Balance at December 31, 2009	$ 14,332
Net (gain) loss	(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 (loss)	(403)
Total reclassification adjustments	(574)
Total change	(5,714)
Balance at December 31, 2010	$ 8,618
Net (gain) loss	**4,980**
Change in prior service costs/transition obligation	**-**
Reclassification adjustments:	
Amortization of transition obligation	**(228)**
Amortization of prior service costs	**188**
Amortization of net gain (loss)	**(234)**
Total reclassification adjustments	**(274)**
Total change	**4,706**
Balance at December 31, 2011	**$ 13,324**

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

	2011	2010	2009
		(in thousands)	
Service cost	**$ 1,012**	$ 1,305	$ 1,328
Interest cost	**4,292**	4,763	5,535
Expected return on plan assets	**(1,763)**	(1,826)	(1,783)
Net amortization	**274**	574	919
Net postretirement cost	**$ 3,815**	$ 4,816	$ 5,999

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2012	$ 5,003	$ (584)	$ 4,419
2013	5,366	(643)	4,723
2014	5,683	(717)	4,966
2015	6,046	(791)	5,255
2016	6,325	(871)	5,454
2017 to 2021	34,852	(4,503)	30,349

Benefit Plan Assets

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

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2011 and 2010, along with the targeted mix of assets for each plan, is presented below:

	Target	**2011**	2010
Pension plan assets:			
Domestic equity	26%	**29%**	29%
International equity	25	**25**	27
Fixed income	23	**23**	22
Special situations	3	**-**	-
Real estate investments	14	**14**	13
Private equity	9	**9**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	20%	**22%**	23%
International equity	20	**20**	22
Fixed income	40	**40**	38
Special situations	2	**-**	-
Real estate investments	11	**11**	10
Private equity	7	**7**	7
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2011 and 2010. The fair values presented are prepared in accordance with applicable accounting standards regarding fair value. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

The fair values of pension plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2011:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 47,911	$ 22,115	$ -	$ 70,026
International equity*	49,250	14,111	-	63,361
Fixed income:				
U.S. Treasury, government, and agency bonds	-	17,960	-	17,960
Mortgage- and asset-backed securities	-	5,605	-	5,605
Corporate bonds	-	34,552	112	34,664
Pooled funds	-	15,757	-	15,757
Cash equivalents and other	28	5,773	-	5,801
Real estate investments	9,119	-	32,434	41,553
Private equity	-	-	24,151	24,151
Total	$ 106,308	$115,873	$ 56,697	$ 278,878

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

As of December 31, 2010:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in 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
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.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in thousands)		
Beginning balance	**$ 27,976**	**$ 26,475**	$ 21,195	$ 21,498
Actual return on investments:				
Related to investments held at year end	**2,964**	**(498)**	3,959	4,313
Related to investments sold during the year	**830**	**1,951**	747	747
Total return on investments	**3,794**	**1,453**	4,706	5,060
Purchases, sales, and settlements	**664**	**(3,777)**	2,075	(83)
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$ 32,434**	**$ 24,151**	$ 27,976	$ 26,475

The fair values of other postretirement benefit plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 2,733	$ 1,260	$ -	$ 3,993
International equity*	2,807	804	-	3,611
Fixed income:				
U.S. Treasury, government, and agency bonds	-	4,796	-	4,796
Mortgage- and asset-backed securities	-	320	-	320
Corporate bonds	-	1,968	-	1,968
Pooled funds	-	898	-	898
Cash equivalents and other	1	987	-	988
Real estate investments	520	-	1,851	2,371
Private equity	-	-	1,377	1,377
Total	$ 6,061	$ 11,033	$ 3,228	$ 20,322

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

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$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
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.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	(in thousands)			
Beginning balance	**$ 1,625**	**$ 1,538**	$ 1,475	$ 1,497
Actual return on investments:				
Related to investments held at year end	**141**	**(29)**	29	47
Related to investments sold during the year	**47**	**85**	-	-
Total return on investments	**188**	**56**	29	47
Purchases, sales, and settlements	**38**	**(217)**	121	(6)
Ending balance	**$ 1,851**	**$ 1,377**	$ 1,625	$ 1,538

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2011, 2010, and 2009 were $3.8 million, $3.8 million, and $3.9 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

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

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by the Company, and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation to the Company with respect to the Company's Plant Watson. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by the Company) in the U.S. District Court for the Northern District of Alabama.

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

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

Climate Change Litigation

Kivalina Case

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

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. The feasibility study/presumptive remedy document was originally filed with TCEQ in June 2011 and remains under consideration by the agency. Amounts expensed and accrued during 2009, 2010, and 2011 related to this work were not material. The Company currently has $0.4 million recorded to other deferred credits and liabilities on the balance sheet for potential remediation. 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 2008, the Company filed a request with the FERC for the Company's revised wholesale Municipal and Rural Association (MRA) cost-based electric tariff (Tariff) and revised rates under the Tariff. 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 in January 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 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 rates under its Tariff. 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 allowed 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 was 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 2010 through December 2010 and allowed 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). In December 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.

On November 2, 2011, the Company filed a request with the FERC for revised rates under its Tariff. The requested revised rates provide for an increase in annual base wholesale revenues in the amount of approximately $32 million, effective January 1, 2012. In this filing, the Company is also (i) seeking approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) seeking authorization to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) seeking authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules. On December 29, 2011, the Company received an order from the FERC accepting, but suspending for a nominal period, the proposed rate change and establishing a hearing and settlement procedure if an agreement with the wholesale customers could not be reached. On January 20, 2012, the Company reached a settlement agreement with its wholesale customers, which has been executed by all parties. The settlement agreement is currently under review by the FERC staff. The settlement agreement provides that base rates under the Tariff will increase approximately $22.6 million over a 12-month period with revised rates to be effective April 1, 2012. In 2012, the amount of base rate revenues to be received from the agreed upon increase will be approximately $17.0 million. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase is due to a change in the CWIP recovery on the Kemper IGCC. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The settlement agreement states that for future rate matters requiring regulatory accounting approval, the Company may follow for accounting and Tariff rate recovery purposes, the treatment allowed by the Mississippi PSC, if such treatment is not in violation of a FERC policy or rule and if agreed to by the wholesale customers. The Tariff customers specifically agreed to the same regulatory treatment for Tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (a) the accounting for Kemper IGCC-related costs that cannot be capitalized, (b) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (c) the establishment of a regulatory asset for certain potential plant retirement costs. The ultimate outcome of this matter cannot be determined at this time.

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 to 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 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 2004 order, the Mississippi PSC ordered that the MPUS 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 2009, concurrent with this review, the annual PEP evaluation filing for 2009 was suspended and the MPUS and the Company filed a joint report with the Mississippi PSC proposing several changes to the PEP. The Mississippi PSC approved the revised PEP in 2009, which resulted in a lower performance incentive under the PEP and therefore smaller and/or less frequent rate changes in the future. Later that year, 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. In November 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 MPUS contested the filing. On June 7, 2011, the Mississippi PSC issued an order approving a joint stipulation between the MPUS and the Company resulting in no change in rates. On November 15, 2011, the Company filed its annual PEP filing for 2012, which indicated a rate increase of 1.893%, or $17.4 million, annually. On January 10, 2012, the MPUS contested the filing. The ultimate outcome of this matter cannot be determined at this time.

In 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, 2011, the Company had fully amortized these costs.

In connection with the purchase of Plant Daniel Units 3 and 4, the Company filed a request on July 25, 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized the Company to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into rates over the remaining life of Plant Daniel Units 3 and 4.

In March 2010, the Company submitted its annual PEP lookback filing for 2009, which recommended no surcharge or refund. In October 2010, the Company and the MPUS agreed and stipulated that no surcharge or refund is required. In November 2010, the Mississippi PSC accepted the stipulation.

On March 15, 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. On May 2, 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. On or before March 15, 2012, the Company will submit its annual PEP lookback filing for 2011. The ultimate outcome of these matters 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 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 MPUS 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.

In 2009, the Company submitted its 2009 SRR rate filing with the Mississippi PSC, which proposed that the SRR rate level remain at zero and the Company be allowed to accrue approximately $4.0 million to the property damage reserve in 2009. Subsequently in 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 31, 2011, the Company submitted its 2011 SRR rate filing with the Mississippi PSC, which proposed that the 2011 SRR rate level remain at zero and the Company be allowed to accrue $3.6 million to the property damage reserve in 2011. On February 2, 2012, the Company submitted its 2012 SRR rate filing with the Mississippi PSC, which proposed that the 2012 SRR rate level remain at zero and the Company be allowed to accrue approximately $4 million to the property damage reserve in 2012. The ultimate outcome of this matter cannot be determined at this time.

Environmental Compliance Overview Plan

On February 14, 2012, the Company submitted its 2012 ECO Plan notice which proposed a 0.3% increase in annual revenues for the Company. The ultimate outcome of this matter cannot be determined at this time.

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. On April 7, 2011, due to changes in ECO Plan cost projections, the Company submitted a revised 2011 ECO Plan which changed the requested annual revenues to a $0.9 million decrease. On May 5, 2011, the revised ECO Plan filing was approved by the Mississippi PSC with the new rates effective in May 2011.

In February 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, in August 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. In October 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 MPUS 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 decided not to pursue the change in the true-up provision.

In July 2010, the Company filed a request for a CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million. The project is scheduled for completion in late 2015. The Company's portion of the cost, if approved by the Mississippi PSC, is expected to be recovered through the ECO Plan. On May 5, 2011, in conjunction with the ECO Plan approval, the Mississippi PSC approved up to $19.5 million (with respect to the Company's ownership portion) in additional spending for 2011 for the scrubber project. As of December 31, 2011, total project expenditures were $45.6 million, with the Company's portion being $22.8 million. During the Mississippi PSC's open meeting held on January 11, 2012, the Mississippi PSC requested additional information on the scrubber project and updates to the filing have been made. The ultimate outcome of these matters cannot be determined at this time.

On November 10, 2011, the Company filed a request to establish a regulatory asset to defer certain plant retirement costs if such costs are incurred. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. These environmental rules and regulations are continuously being monitored by the Company and all options are being evaluated. On December 6, 2011, an order was granted by the Mississippi PSC authorizing the Company to defer all plant retirement related costs resulting from compliance with environmental regulations as a regulatory asset for future recovery.

Certificated New Plant

On April 27, 2011, the Company 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. As part of the review of the mechanism, the Mississippi PSC will consider costs to be included as well as the allowed rate of return. CNP-A rate filings are made annually. The first filing was made on November 15, 2011 and requested an 11.66% increase in rates, or approximately $98 million annually, to recover these financing costs. If approved by the Mississippi PSC, 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.

On August 9, 2011, the Company submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-B (CNP-B) 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. Under the proposed CNP-B, the Company's allowed cost of capital would be adjusted based on certain operational performance indicators. The ultimate outcome of these matters 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, 2011. On January 6, 2012, a revised filing was made with the Mississippi PSC requesting recovery over an 11 month period. The Mississippi PSC approved the retail fuel cost recovery factor on January 11, 2012, with the new rates effective in February 2012. The retail fuel cost recovery factor will result in an annual decrease in an amount equal to 2.2% of total 2011 retail revenue. At December 31, 2011, the amount of over recovered retail fuel costs included in the balance sheets was $42.4 million compared to $55.2 million at December 31, 2010. The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2012, the wholesale MRA fuel rate decreased, resulting in an annual decrease in an amount equal to 3.0% of total 2011 MRA revenue. Effective February 1, 2012, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 4.3% of total 2011 MB revenue. At December 31, 2011, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $14.3 million and $2.2 million compared to $17.5 million and $4.4 million, respectively, at December 31, 2010. In addition, at December 31, 2011, the amount of over recovered MRA emissions allowance cost included in the balance sheets was $1.7 million. 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.

On March 31, 2011, a portion of the Company's territorial wholesale loads that was formerly served under the MB tariff terminated service. Beginning on April 1, 2011, a new power purchase agreement (PPA) went into effect to cover these MB customers as non-territorial load. On June 21, 2011, the Company and South Mississippi Electric Power Association (SMEPA) reached an agreement to allocate $3.7 million of the over recovered fuel balance at March 31, 2011 to the PPA. This amount was subsequently refunded to SMEPA on June 27, 2011.

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 2010 audit was completed in the first quarter 2011 with no audit findings. The 2011 audit of fuel-related expenditures began in the second quarter 2011 and was completed in the fourth quarter 2011 with no audit findings.

Storm Damage Cost Recovery

In March 2009, the Company filed with the Mississippi PSC its final accounting of the restoration costs relating to Hurricane Katrina and the storm operations center. On August 4, 2011, the Mississippi PSC issued an order approving the filing. The final net retail receivable of $3.2 million was recovered on October 21, 2011.

Integrated Coal Gasification Combined Cycle

The Company is constructing the Kemper IGCC that will utilize an IGCC technology with an output capacity of 582 MWs. In May 2010, the Company filed a motion with the Mississippi PSC accepting the conditions contained in the Mississippi PSC order confirming the Company's application for a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC. In June 2010, the Mississippi PSC issued the CPCN.

The estimated cost of the plant is $2.4 billion, net of $245.3 million of grants awarded to the project by the DOE under the CCPI2. The Mississippi PSC's order (1) approved a construction cost cap of up to $2.88 billion (exemptions from the cost cap include the cost of the lignite mine and equipment and the carbon dioxide (CO_2) pipeline facilities), (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, which provided for the accrual of AFUDC in 2010 and 2011 and provides for the 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. Of the total costs incurred through March 2009, $46 million has been reviewed and approved by the Mississippi PSC. A decision regarding the remaining $5 million has been deferred to a later date. The timing of the review of the remaining Kemper IGCC costs is uncertain.

The Kemper IGCC plant, expected to begin commercial operation in May 2014, will use locally mined lignite (an abundant, lower heating value coal) from a mine adjacent to the plant as fuel. In conjunction with the Kemper IGCC, the Company will own the 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 $245 million. In May 2010, the Company executed a 40-year management fee contract with Liberty Fuels, which will develop, construct, and manage the mining operation. The contract with Liberty Fuels is effective June 2010 through the end of the mine reclamation. On December 13, 2011, the Mississippi Department of Environmental Quality (MDEQ) approved the surface coal mining and the water pollution control permits for the mining operation operated by Liberty Fuels. On January 12, 2012, two individuals each filed a notice of appeal and a request for evidentiary hearing with the MDEQ regarding the surface coal mining and water pollution control permits.

In 2009, the Company received notification from the Internal Revenue Service (IRS) formally certifying that the IRS allocated $133 million of Internal Revenue Code Section 48A tax credits (Phase I) to the Company. On April 19, 2011, the Company received notification from the IRS formally certifying that the IRS allocated $279 million of Internal Revenue Code Section 48A tax credits (Phase II) to the Company. 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 credits, the Company plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the plant during operations in accordance with the recapture rules for Section 48A investment tax credits. Through December 31, 2011, the Company received or accrued tax benefits totaling $99.6 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2011 and 2012, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $77.4 million of these tax credits until after 2012. IRS guidelines allow these unused credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then.

In 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 and, later in 2008, an agreement was reached to assign the remaining funds ($270 million) to the Kemper IGCC. Through December 31, 2011, the Company has received grant funds of $245.3 million that were used for the construction of the Kemper IGCC. An additional $25 million is expected to be received for its initial operation.

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 for the Kemper IGCC asking for a preliminary and permanent injunction on the issuance of CCPI2 funds and loan guarantees and a stay to any related construction activities based upon alleged deficiencies in the DOE's environmental impact statement. The Company intervened as a party in this lawsuit on May 18, 2011. On November 18, 2011, the U.S. District Court for the District of Columbia denied the Sierra Club's motion for preliminary injunction in the case and dismissed with prejudice the portion of the Sierra Club's claim relating to loan guarantees. On February 2, 2012, the Sierra Club filed for a voluntary dismissal with prejudice of all remaining claims against the DOE pending in the U.S. District Court for the District of Columbia.

In March 2010, the MDEQ issued the Prevention of Significant Deterioration (PSD) air permit modification for the Kemper IGCC, which modifies the original PSD air permit issued in 2008. The Sierra Club requested a formal evidentiary hearing regarding the issuance of the modified permit. On April 4, 2011, the MDEQ Permit Board unanimously affirmed the PSD air permit. On June 30, 2011, the Sierra Club appealed the final PSD air permit issued by the MDEQ to the Chancery Court of Kemper County, Mississippi. The Company has intervened as a party in this appeal.

In June 2010, the Sierra Club filed an appeal of the Mississippi PSC's June 2010 decision to grant the CPCN 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 July 2010, the Company and SMEPA entered into an Asset Purchase Agreement whereby SMEPA agreed to 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. In December 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 4, 2011, the Company and Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., entered into a contract pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC. On May 19, 2011, the Company and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tenrgys, LLC, entered into a contract pursuant to which Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC.

On June 7, 2011, consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities for the Kemper IGCC. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date. In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings.

On September 9, 2011, the Company filed a request for confirmation of the Kemper IGCC's CPCN with the Mississippi PSC authorizing the acquisition, construction, and operation of approximately 61 miles of CO_2 pipeline infrastructure at an estimated capital cost of $141 million. On January 11, 2012, the Mississippi PSC affirmed the confirmation of the Kemper IGCC's CPCN for the acquisition, construction, and operation of the CO_2 pipeline.

As of December 31, 2011, the Company had spent a total of $943.3 million on the Kemper IGCC, including regulatory filing costs. Of this total, $917.8 million was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $21.4 million was recorded in other regulatory assets, $3.1 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed.

See Retail Regulatory Matters – "Certificated New Plant" herein for information on the proposed rate schedules related to the Kemper IGCC.

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, 2011, 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%	$ 88,319	$ 42,274
Daniel			
Units 1 and 2	50%	$ 286,722	$142,376

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

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama 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 federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2011	2010	2009
		(in thousands)	
Federal –			
Current	**$(27,099)**	$ 5,399	$ 77,619
Deferred	**65,206**	35,367	(32,980)
	38,107	40,766	44,639
State –			
Current	**(2,473)**	3,319	12,444
Deferred	**6,559**	2,190	(6,869)
	4,086	5,509	5,575
Total	**$ 42,193**	$ 46,275	$ 50,214

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2011	2010
	(in thousands)	
Deferred tax liabilities –		
Accelerated depreciation	**$ 356,857**	$ 321,918
Basis differences	**48,268**	1,499
Energy cost management clause under recovered	**7,880**	10,216
Regulatory assets associated with asset retirement obligations	**7,557**	7,338
Pensions and other benefits	**18,283**	14,739
Regulatory assets associated with employee benefit obligations	**52,410**	35,021
Regulatory assets associated with the Kemper IGCC	**4,618**	4,640
Long-term service agreement	**5,231**	-
OCI	**-**	1
Other	**32,202**	25,677
Total	**533,306**	421,049
Deferred tax assets –		
Federal effect of state deferred taxes	**10,899**	11,323
Fuel clause over recovered	**30,050**	39,779
Other property basis differences	**2,918**	3,013
Pension and other benefits	**70,255**	53,213
Property insurance	**25,349**	23,880
Premium on long-term debt	**29,820**	-
Unbilled fuel	**14,951**	16,703
Long-term service agreement	**-**	4,740
Asset retirement obligations	**7,557**	7,338
Interest rate hedges	**5,763**	-
Investment tax credit carryforward	**77,400**	-
Other	**21,571**	21,614
Total	**296,533**	181,603
Total deferred tax liabilities, net	**236,773**	239,446
Portion included in (accrued) prepaid income taxes, net	**33,624**	42,521
Accumulated deferred income taxes	**$ 270,397**	$ 281,967

At December 31, 2011, the tax-related regulatory assets and liabilities were $26.5 million and $12.1 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. 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 $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 healthcare 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, 2012, as approved by the Mississippi PSC for the retail portion and over five years for the wholesale portion, as approved by the FERC.

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, $1.3 million, and $1.2 million for 2011, 2010, and 2009, respectively. At December 31, 2011, 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, 2011, the Company had $99.6 million in unamortized investment tax credits associated with the Kemper IGCC, which will be amortized over the life of the Kemper IGCC once placed in service. As a result of 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2011 and 2012, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $77.4 million of these tax credits until after 2012. IRS guidelines allow the resultant unused credits to be carried forward for 20 years expiring at the end of 2031, if not utilized before then.

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

Effective Tax Rate

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

	2011	2010	2009
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**1.9**	2.8	2.7
Non-deductible book depreciation	**0.3**	0.3	0.3
Medicare subsidy	**(0.1)**	(0.2)	(0.4)
AFUDC-equity	**(6.3)**	(1.0)	(0.1)
Other	**(0.2)**	(0.8)	(0.8)
Effective income tax rate	**30.6%**	36.1%	36.7%

The Company's 2011 effective tax rate decreased from 2010 primarily due to the increase in non-taxable AFUDC equity related to increased construction expenditures.

Unrecognized Tax Benefits

For 2011, the total amount of unrecognized tax benefits increased by $0.7 million, resulting in a balance of $5.0 million as of December 31, 2011.

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

	2011	2010	2009
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 4,288**	$ 3,026	$ 1,772
Tax positions from current periods	**1,486**	868	1,309
Tax positions from prior periods	**(810)**	611	(55)
Reductions due to settlements	**-**	-	-
Reductions due to expired statute of limitations	**-**	(217)	-
Balance at end of year	**$ 4,964**	$ 4,288	$ 3,026

The change in tax positions from current periods for 2011 relates primarily to the tax accounting method change for repairs-generation assets and State of Mississippi tax credits. The tax positions decrease from prior periods for 2011 relates to the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets. See "Tax Method of Accounting for Repairs" below for additional information.

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

	2011	2010	2009
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 4,144**	$ 3,058	$ 3,026
Tax positions not impacting the effective tax rate	**820**	1,230	-
Balance of unrecognized tax benefits	**$ 4,964**	$ 4,288	$ 3,026

The tax positions impacting the effective tax rate for 2011 primarily relate to the State of Mississippi Investment Tax Credit and the production activities deduction tax position. See "Effective Tax Rate" above for additional information. The tax positions not impacting the effective tax rate for 2011 relate to the timing difference associated with the tax accounting method change for repairs - generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2011	2010	2009
		(in thousands)	
Interest accrued at beginning of year	**$413**	$230	$203
Interest reclassified due to settlements	**-**	-	-
Interest accrued during the year	**267**	183	27
Balance at end of year	**$680**	$413	$230

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

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of federal or state audits, could 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 and is currently auditing the federal income tax returns for 2007-2009. For tax years 2010 through 2012, the Company is in the Compliance Assurance Program of the IRS. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

The Company submitted a tax accounting method change for repair costs associated with its generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $5 million for the Company. On August 19, 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine repair costs for transmission and distribution property. Based upon this guidance from the IRS, the uncertain tax position for the tax accounting method change for repairs - transmission and distribution assets has been removed. However, the IRS continues to work with the utility industry in an effort to resolve the repair costs for generation assets matter in a consistent manner for all utilities. On December 23, 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2012. The utility industry anticipates more detailed guidance concerning these regulations. Due to uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time.

6. FINANCING

Bank Term Loans

In April 2011, the Company entered into a one-year $75 million aggregate principal amount long-term floating rate bank loan with a variable interest rate 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 September 2011, the Company entered into a one-year $40 million aggregate principal amount floating rate bank loan that bears interest based on one-month LIBOR. In addition, the Company entered into a one-year extension of a $125 million aggregate principal amount floating rate bank loan that bears interest based on one-month LIBOR. The proceeds were used to repay outstanding short-term debt and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2011 and 2010, the Company had $240 million and $205 million of bank loans outstanding, respectively.

Senior Notes

In October 2011, the Company issued $150 million aggregate principal amount of Series 2011A 2.35% Senior Notes due October 15, 2016 and $150 million aggregate principal amount of Series 2011B 4.75% Senior Notes due October 15, 2041. The Company also settled hedges totaling $150 million related to the Series 2011A issuance at a gain of approximately $1.4 million. This gain will be amortized to interest expense, in earnings, over five years. The Company also settled hedges totaling $150 million related to the Series 2011B issuance at a loss of approximately $0.5 million. This loss will be amortized to interest expense, in earnings, over 10 years. The net proceeds were used by the Company to pay amounts in connection with the purchase of Plant Daniel Units 3 and 4 as described in Note 1 under "Purchase of the Plant Daniel Combined Cycle Generating Units," and for general corporate purposes, including the Company's continuous construction program.

The Company had a total of $630.0 million and $330.0 million, respectively, of senior notes outstanding at December 31, 2011 and 2010.

Plant Daniel Revenue Bonds

In October 2011, in connection with the Company's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, the Company assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor as described in Note 1 under "Purchase of the Plant Daniel Combined Cycle Generating Units" herein. These bonds are secured by Plant Daniel Units 3 and 4 and certain personal property. The bonds were recorded at fair value as of the date of assumption, or $346.1 million, reflecting a premium of $76.1 million.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2011 and 2010 was as follows:

	2011	2010
	(in millions)	
Capitalized leases	$ 0.6	$ 1.4
Bank term loans	240.0	205.0
Revenue bonds	-	50.0
Outstanding at December 31	**$ 240.6**	$ 256.4

Maturities applicable to total long-term debt are $240.6 million in 2012, $50.0 million in 2013, and $150.0 million in 2016. 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, 2011 and 2010 was $82.7 million.

Other Revenue Bonds

Other revenue bond obligations represent loans to the Company from a public authority of funds derived from the sale by such authority of revenue bonds. The Company had $50 million and $100 million of such obligations outstanding at December 31, 2011 and 2010, respectively. Such amounts are reflected in the statements of capitalization as long-term notes payable.

Assets Subject to Lien

The revenue bonds assumed in conjunction with the purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain personal property. See Note 1 under "Purchase of the Plant Daniel Combined Cycle Generating Units" for additional information.

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

Expires[a]				Executable Term-Loans	
2012	2014	Total	Unused	One Year	Two Years
			(in millions)		
$131	$165	$296	$296	$25	$41

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

The Company expects to renew its credit arrangements, 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 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 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, 2011, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowing.

This $296 million in unused credit arrangements provides required liquidity support to the Company's borrowings through a commercial paper program. The credit arrangements also provide support to the Company's variable rate tax-exempt pollution control revenue bonds totaling $40.1 million.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$-	-%	$ 7	0.21%	$70
December 31, 2010:					
Commercial paper	$-	-%	$ 12	0.28%	$63

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

7. COMMITMENTS

Construction Program

The construction program of the Company is currently estimated to include a base level investment of $1.5 billion, $363 million, and $352 million for 2012, 2013, and 2014, respectively. Included in these estimated amounts are expenditures related to the Kemper IGCC of $1.3 billion, $124 million, and $74 million in 2012, 2013, and 2014, respectively, which are net of SMEPA's 17.5% expected ownership share of the Kemper IGCC of approximately $466 million and $16 million in 2013 and 2014, respectively. These estimated base level investment amounts include capital expenditures covered under long-term service agreements. Also included in these estimated amounts are base level environmental expenditures to comply with existing statutes and regulations of $87 million, $113 million, and $154 million for 2012, 2013, and 2014, respectively. These base level environmental expenditures do not include potential incremental environmental compliance investments associated with compliance with the EPA's final Mercury and Air Toxics Standards rule and proposed water and coal combustion byproducts rules, except with respect to $354 million which is included in the Company's base level capital investment in anticipation of these rules. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; 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, 2011, significant purchase commitments were outstanding in connection with the continuous 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 Plant Daniel Units 3 and 4. 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 expense of $12.9 million through October 20, 2011, $12.6 million for 2010, and $13.3 million for 2009, respectively, which is included in other operations and maintenance expense in the statements of income.

Effective October 21, 2011, concurrent with the Company's purchase of Plant Daniel Units 3 and 4, payments under the Company's LTSA with GE for Plant Daniel Units 3 and 4 are being recorded as prepayments on the balance sheet until the work is performed. Remaining payments to GE under the LTSA are currently estimated to total $90.2 million over approximately eight 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 $13.7 million over the remaining term of the LTSA, which is approximately five 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 its 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, 2011.

Total estimated minimum long-term commitments at December 31, 2011 were as follows:

	Commitments	
	Natural Gas	Coal
	(in thousands)	
2012	$ 159,394	$ 267,075
2013	149,890	49,765
2014	115,536	8,440
2015	95,005	960
2016	86,481	960
2017 and thereafter	146,169	35,520
Total	$ 752,475	$ 362,720

Coal commitments include a management fee of $38.1 million over the term of the executed 40-year management contract with Liberty Fuels beginning in 2014 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 credit rating of Southern Power is currently below that of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense for the Company was $32.6 million, $38.6 million, and $39.1 million for 2011, 2010, and 2009 respectively, which includes the Plant Daniel Units 3 and 4 operating lease that ended October 20, 2011.

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. In early 2011, one operating lease expired and the Company elected not to exercise the option to purchase. The remaining operating lease has 234 aluminum rail cars. 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 $2.6 million in 2011, $3.5 million in 2010, and $4.0 million in 2009. The Company's annual railcar lease payments for 2012 through 2016 will average approximately $2.1 million and after 2016, lease payments total in aggregate approximately $0.5 million.

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 $0.4 million in 2011 and $0.7 million in 2010. The Company's annual lease payments for 2012 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 $7.5 million in 2011 and $8.4 million in 2010 related to barges and tow/shift boats. The Company's annual lease payments for 2012 through 2014 with respect to these barge transportation leases will average approximately $8.2 million.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2011, there were 271 current and former employees of the Company participating in the stock option program and there were 47 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	**2011**	2010	2009
Expected volatility	**17.5%**	17.4%	15.6%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.3%**	2.4%	1.9%
Dividend yield	**4.8%**	5.6%	5.4%
Weighted average grant-date fair value	**$3.23**	$2.23	$1.80

The Company's activity in the stock option program for 2011 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2010	1,843,370	$32.30
Granted	261,718	37.99
Exercised	(535,018)	31.31
Cancelled	(342)	32.33
Outstanding at December 31, 2011	**1,569,728**	**$33.59**
Exercisable at December 31, 2011	**967,865**	**$33.22**

The number of stock options vested, and expected to vest in the future, as of December 31, 2011 was not significantly different from the number of stock options outstanding at December 31, 2011 as stated above. As of December 31, 2011, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $19.9 million and $12.6 million, respectively.

As of December 31, 2011, 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 11 months.

For the years ended December 31, 2011, 2010, and 2009, total compensation cost for stock option awards recognized in income was $0.8 million, $0.8 million, and $0.9 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.3 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, 2011, 2010, and 2009 was $4.2 million, $2.7 million, and $0.4 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.6 million, $1.0 million, and $0.2 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Performance Shares

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

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. Expected volatility used in the model for 2011 and 2010 was 19.2% and 20.7%, respectively. The expected volatility is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate of 1.4% for 2011 and 1.4% for 2010 was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units. The annualized dividend rate at the time of grant was $1.82 and $1.75 for 2011 and 2010, respectively. The weighted-average grant date fair value for units granted during 2010 was $30.13. Total unvested performance share units outstanding as of December 31, 2010 was 36,981. During 2011, 35,067 performance share units were granted with a weighted-average grant date fair value of $35.97. During 2011, 1,218 performance share units were forfeited resulting in 70,830 unvested units outstanding at December 31, 2011.

For the years ended December 31, 2011 and 2010, total compensation cost for performance share units recognized in income was $0.7 million and $0.3 million, respectively, with the related tax benefit also recognized in income of $0.3 million and $0.1 million, respectively. As of December 31, 2011, there was $1.2 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 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			
At December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ -	$ 162	$ -	$ 162
Foreign currency derivatives	-	1,526	-	1,526
Cash equivalents	133,900	-	-	133,900
Total	$133,900	$ 1,688	$ -	$135,588
Liabilities:				
Energy-related derivatives	$ -	$ 51,152	$ -	$ 51,152
Interest rate derivatives	-	15,208	-	15,208
Foreign currency derivatives	-	2,510	-	2,510
Total	$ -	$ 68,870	$ -	$ 68,870

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 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 10 for additional information on how these derivatives are used.

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

	Fair Value	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice Period**
As of December 31, 2011	*(in thousands)*			
Cash equivalents:				
Money market funds	$133,900	None	Daily	Not applicable
As of December 31, 2010				
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, 2011 and 2010, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2011	**$ 1,343,596**	**$ 1,426,808**
2010	$ 716,399	$ 738,211

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, 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, 2011, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Gas		
Net Purchased mmBtu*	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in millions)		
31	2017	-

* mmBtu - million British thermal units

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

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 typically recorded directly to earnings, however, the Company has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

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

	Notional Amount	Forward Rate	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2011
	(in millions)			*(in thousands)*
Fair value hedges of firm commitments				
	EUR9.2	1.371 Dollars per Euro*	Various through March 2014	$(652)
Derivatives not designated as hedges				
	EUR18.1	1.317 Dollars per Euro*	N/A	(332)
Total				$(984)

* Weighted Average

During the year ended December 31, 2011, certain fair value hedges were de-designated. The ineffectiveness related to the de-designated hedges was recorded as a regulatory asset and was immaterial to 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, 2011, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2011
	(in millions)				*(in millions)*
Cash flow hedges of forecasted debt					
	$300	3-month LIBOR	2.66%*	April 2022	$(15)

*Weighted Average

For the year ended December 31, 2011, the Company had realized net gains of $0.8 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.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2012 are $0.8 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2022.

Derivative Financial Statement Presentation and Amounts

At December 31, 2011 and 2010, the fair value of energy-related derivatives, foreign currency derivatives, and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$125**	$ 830	Liabilities from risk management activities	**$36,455**	$27,459
	Other deferred charges and assets	**37**	1,238	Other deferred credits and liabilities	**14,697**	18,386
Total derivatives designated as hedging instruments for regulatory purposes		**$162**	$ 2,068		**$51,152**	$45,845
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	**$ -**	$ 3	Liabilities from risk management activities	**$ -**	$ -
Interest rate derivatives:	Other current assets	**-**	-	Liabilities from risk management activities	**15,208**	-
Foreign currency derivatives:	Other current assets	**19**	2,403	Liabilities from risk management activities	**625**	66
	Other deferred charges and assets	**-**	1,016	Other deferred credits and liabilities	**46**	29
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 19**	$3,422		**$15,879**	$ 95
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ -**	$ 4	Liabilities from risk management activities	**$ -**	$ -
Foreign currency derivatives:	Other current assets	**1,507**	-	Liabilities from risk management activities	**1,839**	-
Total derivatives not designated as hedging instruments		**$1,507**	$ 4		**$ 1,839**	$ -
Total		**$1,688**	$5,494		**$68,870**	$45,940

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

At December 31, 2011 and 2010, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$36,455**	$(27,459)	Other regulatory liabilities, current	$ 125	$ 830
	Other regulatory assets, deferred	**14,697**	(18,386)	Other regulatory liabilities, deferred	37	1,238
Total energy-related derivative gains (losses)		**$51,152**	$(45,845)		$ 162	$2,068

For the years ended December 31, 2011, 2010, and 2009, 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	**2011**	2010	2009	**Statements of Income Location**	**2011**	2010	2009
		(in thousands)				*(in thousands)*	
Energy-related derivatives	**$ (3)**	$3	$-	Fuel	**$ -**	$-	$ -
Interest rate derivatives	**(14,361)**	-	-	Interest Expense	**48**	-	-
Total	**$(14,364)**	$3	$-		**$ 48**	$-	$ -

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

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material. For the year ended December 31, 2011, the pre-tax effect of foreign currency derivatives not designated as hedging instruments was recorded as a regulatory asset and was immaterial to the Company.

For the twelve months ended December 31, 2011, the pre-tax losses from foreign currency derivatives designated as fair value hedging instruments, which include pre-tax losses associated with de-designated hedges prior to de-designation, on the Company's statements of income were $3.6 million. These amounts were offset by 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, 2011, the fair value of derivative liabilities with contingent features was $6.4 million.

At December 31, 2011, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $36 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2011and 2010 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in thousands)	
March 2011	**$263,276**	**$25,151**	**$14,617**
June 2011	**286,041**	**39,056**	**25,283**
September 2011	**325,766**	**53,171**	**38,019**
December 2011	**237,794**	**16,412**	**16,263**
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

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

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

	2011	2010	2009	2008	2007
Operating Revenues (in thousands)	**$1,112,877**	$1,143,068	$1,149,421	$1,256,542	$1,113,744
Net Income After Dividends on Preferred Stock (in thousands)	**$94,182**	$80,217	$84,967	$85,960	$84,031
Cash Dividends on Common Stock (in thousands)	**$75,500**	$68,600	$68,500	$68,400	$67,300
Return on Average Common Equity (percent)	**10.54**	11.49	13.12	13.75	13.96
Total Assets (in thousands)	**$3,671,842**	$2,476,321	$2,072,681	$1,952,695	$1,727,665
Gross Property Additions (in thousands)	**$1,205,704**	$340,162	$95,573	$139,250	$114,927
Capitalization (in thousands):					
Common stock equity	**$1,049,217**	$737,368	$658,522	$636,451	$613,830
Redeemable preferred stock	**32,780**	32,780	32,780	32,780	32,780
Long-term debt	**1,103,596**	462,032	493,480	370,460	281,963
Total (excluding amounts due within one year)	**$2,185,593**	$1,232,180	$1,184,782	$1,039,691	$928,573
Capitalization Ratios (percent):					
Common stock equity	**48.0**	59.8	55.6	61.2	66.1
Redeemable preferred stock	**1.5**	2.7	2.8	3.2	3.5
Long-term debt	**50.5**	37.5	41.6	35.6	30.4
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**151,805**	151,944	151,375	152,280	150,601
Commercial	**33,200**	33,121	33,147	33,589	33,507
Industrial	**496**	504	513	518	514
Other	**175**	187	180	183	181
Total	**185,676**	185,756	185,215	186,570	184,803
Employees (year-end)	**1,264**	1,280	1,285	1,317	1,299

	2011	2010	2009	2008	2007
Operating Revenues (in thousands):					
Residential	**$246,510**	$256,994	$245,357	$248,693	$230,819
Commercial	**263,256**	266,406	269,423	271,452	247,539
Industrial	**275,752**	267,588	269,128	258,328	242,436
Other	**6,945**	6,924	7,041	6,961	6,420
Total retail	**792,463**	797,912	790,949	785,434	727,214
Wholesale - non-affiliates	**273,178**	287,917	299,268	353,793	323,120
Wholesale - affiliates	**30,417**	41,614	44,546	100,928	46,169
Total revenues from sales of electricity	**1,096,058**	1,127,443	1,134,763	1,240,155	1,096,503
Other revenues	**16,819**	15,625	14,658	16,387	17,241
Total	**$1,112,877**	$1,143,068	$1,149,421	$1,256,542	$1,113,744
Kilowatt-Hour Sales (in thousands):					
Residential	**2,162,419**	2,296,157	2,091,825	2,121,389	2,134,883
Commercial	**2,870,714**	2,921,942	2,851,248	2,856,744	2,876,247
Industrial	**4,586,356**	4,466,560	4,329,924	4,187,101	4,317,656
Other	**38,684**	38,570	38,855	38,886	38,764
Total retail	**9,658,173**	9,723,229	9,311,852	9,204,120	9,367,550
Wholesale - non-affiliates	**4,009,637**	4,284,289	4,651,606	5,016,655	5,185,772
Wholesale - affiliates	**648,772**	774,375	839,372	1,487,083	1,026,546
Total	**14,316,582**	14,781,893	14,802,830	15,707,858	15,579,868
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.40**	11.19	11.73	11.72	10.81
Commercial	**9.17**	9.12	9.45	9.50	8.61
Industrial	**6.01**	5.99	6.22	6.17	5.61
Total retail	**8.21**	8.21	8.49	8.53	7.76
Wholesale	**6.52**	6.51	6.26	6.99	5.94
Total sales	**7.66**	7.63	7.67	7.90	7.04
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,229**	15,130	13,762	13,992	14,294
Residential Average Annual Revenue Per Customer	**$1,622**	$1,693	$1,614	$1,640	$1,545
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**3,156**	3,156	3,156	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,618**	2,792	2,392	2,385	2,294
Summer	**2,462**	2,638	2,522	2,458	2,512
Annual Load Factor (percent)	**59.1**	57.9	60.7	61.5	60.9
Plant Availability Fossil-Steam (percent)	**87.7**	93.8	94.1	91.6	92.2
Source of Energy Supply (percent):					
Coal	**34.9**	43.0	40.0	58.7	60.0
Oil and gas	**51.5**	41.9	43.6	28.6	27.1
Purchased power -					
From non-affiliates	**1.4**	1.3	3.3	4.4	3.0
From affiliates	**12.2**	13.8	13.1	8.3	9.9
Total	**100.0**	100.0	100.0	100.0	100.0

Directors

Carl J. Chaney
President and Chief Executive Officer
Hancock Holding Company
Gulfport, Mississippi. Elected 2009

L. Royce Cumbest
Chairman, President, and Chief Executive Officer
Merchants & Marine Bank and Merchants & Marine Bancorp, Inc.
Pascagoula, Mississippi. Elected 2010

Edward Day, VI
President and Chief Executive Officer
Mississippi Power Company
Gulfport, Mississippi. Elected 2010

Christine L. Pickering
Christy Pickering, CPA
Biloxi, Mississippi. Elected 2007

Martha D. Saunders, Ph.D.
President
The University of Southern Mississippi
Hattiesburg, Mississippi. Elected 2008

Philip J. Terrell, Ph.D.
Retired Superintendent
Pass Christian Public School District
Pass Christian, Mississippi. Elected 1995

Marion L. Waters
Partner
Waters International Trucks, Inc.
Meridian, Mississippi. Elected 2010

Officers

Edward Day, VI
President and Chief Executive Officer

Thomas O. Anderson, IV
Vice President
Generation Development

John W. Atherton
Vice President
External Affairs

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer

Jeff G. Franklin (1)
Vice President
Customer Services Organization

Donald R. Horsley (2)
Vice President
Customer Services Organization

R. Allen Reaves
Vice President and
Senior Production Officer

Cynthia F. Shaw
Comptroller

Vicki L. Pierce
Corporate Secretary and Assistant Treasurer

Stacy R. Kilcoyne
Vice President

Melissa K. Caen
Assistant Secretary and Assistant Treasurer

(1) Elected effective August 1, 2011.
(2) Resigned effective July 31, 2011.

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

Profile
The Company operates 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. The Company sells electricity to approximately 186,000 customers within its service area of more than 11,000 square miles in southeast Mississippi. In 2011, retail energy sales accounted for 67.8% of the Company's total sales of 14.3 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.

Registrar, Transfer Agent, and Dividend Paying Agent
All series of Preferred Stock
Computershare
Shareowner Services
P.O. Box 358035
Pittsburgh, PA 15252
(800) 554-7626
www.bnymellon.com/shareowner/equityaccess

Trustee, Registrar, and Interest Paying Agent
All series of Senior Notes
Wells Fargo Bank, N.A.
Corporate Treasury Services
7000 Central Parkway NE
Suite 550
Atlanta, GA 30328
(770) 395-6408

There is no market for the Company's common stock, all of which is owned by Southern Company.

Dividends on the Company's common stock are payable at the discretion of the Company's board of directors. The dividends declared by the Company to its common stockholder for the past two years were as follows:

Quarter	2011	2010
	(in thousands)	
First	$18,875	$17,150
Second	18,875	17,150
Third	18,875	17,150
Fourth	18,875	17,150

Number of Preferred Shareholders of record as of December 31, 2011 was 196.

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 Corporate Office address below:

Corporate Office
Mississippi Power Company
2992 West Beach Boulevard
Gulfport, Mississippi 39501
(228) 864-1211

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

Legal Counsel
Balch & Bingham LLP
P.O. Box 130
Gulfport, Mississippi 39502

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