MISSISSIPPI POWER COMPANY

2012 ANNUAL REPORT

MISSISSIPPI POWER

A SOUTHERN COMPANY

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

Edward Day, VI
President and Chief Executive Officer

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

February 27, 2013

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, 2012 and 2011, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements (pages 34 to 84) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

OVERVIEW

Business Activities

Mississippi Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of rising costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, fuel, 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.

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 2010, the Mississippi PSC issued a certificate 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.

On January 24, 2013, the Company and the Mississippi PSC entered into a settlement agreement (Settlement Agreement) that (i) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to the Company and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (ii) resolves the Company's appeal before the Mississippi Supreme Court related to the new Certificated New Plant-A (CNP-A) rate schedule and stipulated rate increase submitted to the Mississippi PSC on June 14, 2012. The ultimate outcome of this matter cannot be determined at this time. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

In October 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

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 percentage of time customers had electric service (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 customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2012 fossil/hydro Peak Season EFOR was better than the target, excluding the impact of Hurricane Isaac in August 2012. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The 2012 performance was better than the target for these reliability measures.

Net income after dividends on preferred stock is the primary measure of the Company's financial performance. The Company was below target for 2012 net income after dividends on preferred stock primarily due to lower retail revenue under PEP and the Mississippi PSC denial of the 2012 rate recovery filings for the Kemper IGCC, partially offset by lower operations and maintenance expenses and higher allowance for funds used during construction (AFUDC) related to the construction of the Kemper IGCC, which began in 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Performance Evaluation Plan" and FUTURE EARNINGS POTENTIAL – "PSC Matters – Certificated New Plant" herein for additional information.

The Company's 2012 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile overall and in all segments**
Peak Season EFOR*	**4.99% or less**	**0.5%**
Net income after dividends on preferred stock	**$156.9 million**	**$148.1 million**

*Excluding impact of Hurricane Isaac

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. Management continues to emphasize the importance of performing well and employees continue to demonstrate their commitment to achieving or exceeding management's expectations.

Earnings

The Company's net income after dividends on preferred stock was $148.1 million in 2012 compared to $94.2 million in 2011. The 57.3% increase in 2012 was primarily the result of increases in AFUDC equity related to the construction of the Kemper IGCC which began in 2010, a decrease in operations and maintenance expenses, and an increase in territorial base revenues primarily due to a wholesale base rate increase effective April 1, 2012. This increase in net income after dividends on preferred stock was partially offset by an increase in interest expense, net of amounts capitalized. 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 $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 AFUDC equity related to the construction of the Kemper IGCC. 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.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
		(in millions)	
Operating revenues	$ 1,036.0	$ (76.9)	$ (30.2)
Fuel	411.2	(79.2)	(11.4)
Purchased power	55.1	(16.7)	(11.9)
Other operations and maintenance	228.7	(37.7)	(1.7)
Depreciation and amortization	86.6	6.2	3.5
Taxes other than income taxes	79.4	9.3	0.3
Total operating expenses	861.0	(118.1)	(21.2)
Operating income	175.0	41.2	(9.0)
Allowance for equity funds used during construction	64.8	40.1	20.9
Interest income	0.7	(0.6)	1.1
Interest expense, net of amounts capitalized	40.8	19.1	(0.7)
Other income (expense), net	0.5	0.5	(3.8)
Income taxes	50.4	8.2	(4.1)
Net income	149.8	53.9	14.0
Dividends on preferred stock	1.7	—	—
Net income after dividends on preferred stock	$ 148.1	$ 53.9	$ 14.0

Operating Revenues

Operating revenues for 2012 were $1.0 billion, reflecting a $76.9 million decrease from 2011. Details of the Company's operating revenues in 2012 and the prior year were as follows:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	$ 792.5	$ 797.9
Estimated change in —		
Rates and pricing	(2.0)	0.5
Sales growth (decline)	9.0	2.3
Weather	(9.8)	(8.9)
Fuel and other cost recovery	(42.2)	0.7
Retail — current year	747.5	792.5
Wholesale revenues —		
Non-affiliates	255.5	273.2
Affiliates	16.4	30.4
Total wholesale revenues	271.9	303.6
Other operating revenues	16.6	16.8
Total operating revenues	$ 1,036.0	$ 1,112.9
Percent change	(6.9)%	(2.6)%

Total retail revenues for 2012 decreased 5.7% compared to 2011 primarily as a result of lower energy sales primarily due to milder weather and lower fuel cost recovery revenues in 2012 compared to 2011. 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. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates for the 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 energy component of purchased power costs, and do not affect net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information. The fuel and other cost recovery revenues decreased in 2012 compared to 2011 primarily as a result of lower recoverable fuel costs, partially offset by an increase in revenues related to ad valorem taxes. The fuel and other cost recovery revenues increased in 2011 compared to 2010 primarily as a result of higher recoverable fuel costs. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel portion of wholesale revenues from energy sold to customers outside 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 $17.6 million, or 6.5%, in 2012 compared to 2011 as a result of a $31.0 million decrease in energy revenues, of which $23.2 million was associated with lower fuel prices and $7.8 million was associated with a decrease in kilowatt-hour (KWH) sales, partially offset by a wholesale base rate increase effective April 1, 2012. 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 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 2010, partially offset by a wholesale base rate increase effective January 2011.

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 will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Wholesale revenues from sales to affiliated companies decreased 46.1% in 2012 compared to 2011 primarily due to a $1.6 million decrease in capacity revenues and a $12.4 million decrease in energy revenues of which $9.1 million was associated with lower prices and $3.3 million was associated with a decrease in KWH sales. Wholesale revenues from sales to affiliated companies decreased 26.9% in 2011 compared to 2010 primarily due to a $2.5 million decrease in capacity revenues and an $8.7 million decrease in energy revenues of which $2.7 million was associated with lower prices and $6.0 million was associated with a decrease in KWH sales.

Other operating revenues in 2012 decreased $0.2 million, or 1.4%, from 2011 primarily due to a $1.0 million decrease in rent from electric property, partially offset by a $0.9 million increase in transmission revenues. 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.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2012 and percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2012	**2012**	2011	**2012**	2011
	(in millions)				
Residential	**2,046**	**(5.4)%**	(5.8)%	**2.3%**	(0.4)%
Commercial	**2,916**	**1.6**	(1.8)	**1.7**	2.1
Industrial	**4,702**	**2.5**	2.7	**2.5**	2.7
Other	**38**	**(0.2)**	0.3	**(0.2)**	0.3
Total retail	**9,702**	**0.5**	(0.7)	**2.2**	1.8
Wholesale					
Non-affiliated	**3,819**	**(4.8)**	(6.4)		
Affiliated	**572**	**(11.8)**	(16.2)		
Total wholesale	**4,391**	**(5.7)**	(7.9)		
Total energy sales	**14,093**	**(1.6)**	(3.1)		

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

Residential energy sales decreased 5.4% in 2012 compared to 2011 due to milder weather, partially offset by a slight increase in the number of residential customers in 2012 compared to 2011. 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.

Commercial energy sales increased 1.6% in 2012 compared to 2011 due to increased economic activity in 2012 compared to 2011. Commercial energy sales decreased 1.8% in 2011 compared to 2010 due to closer to normal weather in 2011 compared to 2010.

Industrial energy sales increased 2.5% in 2012 compared to 2011 due to increased production for many of the industrial customers resulting from increased economic activity as well as expansions of some existing customers. 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.

Wholesale energy sales to non-affiliates decreased 4.8% in 2012 compared to 2011 primarily due to decreased KWH sales to rural electric cooperative associations and municipalities located in southeastern Mississippi resulting from milder weather in 2012 compared to 2011. KWH 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.

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 11.8% in 2012 compared to 2011 and 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.

Fuel and Purchased Power Expenses

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

Details of the Company's generation and purchased power were as follows:

	2012	2011	2010
Total generation *(millions of KWHs)*	**12,750**	12,986	13,146
Total purchased power *(millions of KWHs)*	**1,961**	2,055	2,330
Sources of generation *(percent)* –			
Coal	**26**	40	51
Gas	**74**	60	49
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**5.09**	4.39	4.08
Gas	**2.90**	3.88	4.22
Average cost of fuel, generated *(cents per net KWH)*	**3.53**	4.10	4.14
Average cost of purchased power *(cents per net KWH)*	**2.81**	3.49	3.59

Fuel and purchased power expenses were $466.4 million in 2012, a decrease of $95.9 million, or 17.1% below the prior year costs. The decrease was primarily due to a $70.5 million decrease in the cost of fuel and purchased power and a $25.4 million decrease related to lower total KWHs generated and purchased. 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. The decrease was primarily due to a $16.5 million decrease related to lower total KWHs generated and purchased and a $6.8 million decrease in the cost of fuel and purchased power.

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

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through 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.

Fuel

Fuel expense decreased $79.2 million in 2012 compared to 2011. Approximately $66.2 million of the reduction in fuel expenses resulted primarily from lower fuel prices and a $13.0 million decrease in generation from Company-owned facilities. 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.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates decreased $1.0 million, or 16.3%, in 2012 compared to 2011. The decrease was primarily the result of a 41.2% decrease in the average cost of purchased power per KWH, partially offset by a 42.3% increase in volume of KWHs purchased. The decrease in the average cost per KWH purchased was due to a lower marginal cost of fuel. The increase in the volume of KWHs purchased was due to a lower market cost of available energy compared to the cost of generation. Purchased power expense from non-affiliates decreased $2.2 million, or 26.0%, in 2011 compared to 2010. The decrease was primarily the result of a 32.4% decrease in the average cost of purchased power per KWH, partially offset by a 9.5% increase in volume of KWHs purchased.

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

Purchased Power - Affiliates

Purchased power expense from affiliates decreased $15.7 million, or 23.9%, in 2012 compared to 2011. The decrease was primarily the result of a 15.4% decrease in the average cost of purchased power per KWH and a 10.0% decrease in volume of KWHs purchased. Purchased power expense from affiliates decreased $9.7 million, or 12.8%, in 2011 compared to 2010. The decrease was primarily the result of a 13.7% decrease in volume of KWHs purchased, partially offset by a 1.0% increase in the average cost of purchased power per KWH.

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

Other Operations and Maintenance Expenses

Other operations and maintenance expenses decreased $37.7 million in 2012 compared to 2011 primarily due to a $34.7 million decrease in rent expense and expenses under a long-term service agreement resulting from the expiration of the Plant Daniel Units 3 and 4 operating lease in October 2011 and a $6.3 million decrease in generation maintenance expenses for several major outages. These decreases were partially offset by a $2.8 million increase in administrative and general expenses. See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.

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 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.

Depreciation and Amortization

Depreciation and amortization increased $6.2 million in 2012 compared to 2011 primarily due to a $10.8 million increase in depreciation resulting from an increase in plant in service and a $6.2 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 $4.5 million decrease in amortization resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4, a $3.3 million decrease in Environmental Compliance Overview (ECO) Plan amortization, and a $2.4 million decrease in amortization resulting from a regulatory deferral associated with operations and maintenance expenses that ended in 2011.

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 a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4 and a $0.7 million decrease in ECO Plan amortization.

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 $9.3 million in 2012 compared to 2011 primarily as a result of an $11.7 million increase in ad valorem taxes resulting from the expiration of a tax exemption related to Plant Daniel Units 3 and 4, partially offset by a $2.2 million decrease in franchise taxes and a $0.2 million decrease in payroll 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.

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

Allowance for Funds Used During Construction Equity

AFUDC equity increased $40.1 million in 2012 as compared to 2011 and $20.9 million in 2011 as compared to 2010. These increases were primarily due to increases in construction work in progress (CWIP) related to the construction of the Kemper IGCC which began in 2010. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $19.1 million in 2012 compared to 2011, primarily due to a $39.0 million increase in interest expense associated with the issuances of new long-term debt in October 2011, March 2012, August 2012, and November 2012, and a $12.5 million increase in interest expense resulting from the receipt of a $150.0 million interest-bearing refundable deposit from South Mississippi Electric Power Association (SMEPA) in March 2012 related to its pending purchase of an undivided interest in the Kemper IGCC. These increases were partially offset by a $22.8 million increase in capitalized interest primarily resulting from AFUDC debt associated with the Kemper IGCC, a $6.1 million decrease in interest expense resulting from the amortization of the fair value adjustment in the assumed debt related to the purchase of Plant Daniel Units 3 and 4 in October 2011, and a $3.5 million decrease in interest expense associated with the redemption of long term debt in 2012.

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 amortization of the fair value adjustment in 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.

Other Income (Expense), Net

Other income (expense), net increased $0.5 million in 2012 compared to 2011 primarily due to a $1.6 million increase in the sale of property and a $1.1 million increase in non-operating income, partially offset by a $1.9 million increase in other deductions. 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.

Income Taxes

Income taxes increased $8.2 million, or 19.4%, in 2012 compared to 2011 primarily resulting from higher pre-tax earnings and an increase due to lower State of Mississippi manufacturing investment tax credits, partially offset by an increase in AFUDC equity, which is non-taxable, and a decrease in unrecognized tax benefits. 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.

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 and the successful completion of ongoing construction projects, including construction of generating facilities. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in economic conditions impact sales for the Company, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

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

New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, 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 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. In March 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. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

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

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2012, the Company had invested approximately $300 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $52 million, $23 million, and $2 million for 2012, 2011, and 2010, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $419 million from 2013 through 2015, with annual totals of approximately $129 million, $174 million, and $116 million for 2013, 2014, and 2015, respectively.

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

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $183 million in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

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

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. In 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, unless a one-year compliance extension is granted by the state or local air permitting agency. The Company has received this one-year compliance extension for Plant Daniel to April 16, 2016.

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

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

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

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

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

Water Quality

In April 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.

Coal Combustion Byproducts

The Company currently operates two electric generating plants with on-site coal combustion byproducts 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 has its own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA continues to evaluate the regulatory program for coal combustion byproducts, including coal ash and gypsum, under federal solid and hazardous waste laws. In 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts.

While the ultimate outcome of this matter cannot be determined at this time and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.

Environmental Remediation

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

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

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

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. 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 EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company reported 2011 greenhouse gas emissions of approximately 9 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 7 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.

FERC Matters

In November 2011, the Company filed a request with the FERC for an increase in wholesale base revenues of approximately $32 million under the wholesale cost-based electric tariff. In its filing with the FERC, the Company sought (i) 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) 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) 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 March 9, 2012, the Company entered into a settlement agreement with its wholesale customers with respect to the Company's request for revised rates under the wholesale cost-based electric tariff. The settlement agreement provides that base rates under the cost-based electric tariff will increase by approximately $22.6 million over a 12-month period with revised rates effective April 1, 2012. 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 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 (i) the accounting for Kemper IGCC-related costs that cannot be capitalized, (ii) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (iii) the establishment of a regulatory asset for certain potential plant retirement costs.

On March 28, 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. On September 27, 2012, the Company, with its wholesale customers, filed a final settlement agreement with the FERC. On November 5, 2012, the settlement judge certified the settlement agreement to the FERC with the recommendation that it be approved. The FERC has not yet approved the settlement agreement. The ultimate outcome of this matter cannot be determined at this time.

PSC Matters

General

On August 7, 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing for informational purposes only the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. The ultimate outcome of this matter cannot be determined at this time.

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 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. In January 2011, the MPUS contested the filing. In June 2011, the Mississippi PSC issued an order approving a joint stipulation between the MPUS and the Company resulting in no change in rates.

In November 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.

In March 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. In May 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. On April 2, 2012, the Company filed a motion to suspend the PEP lookback filing for 2011. Unresolved matters related to certain costs included in the 2010 PEP lookback filing also impact the 2011 PEP lookback filing, making it impractical to determine the Company's actual retail return on investment for 2011 for purposes of the 2011 PEP lookback filing. An order granting the suspension of the 2011 PEP lookback was signed by the Mississippi PSC on May 8, 2012. On or before March 15, 2013, the Company will submit its annual PEP lookback filing for 2012. While the Company does not expect the resolution of these unresolved matters to have a material impact on its financial statements, the ultimate outcome of these matters cannot be determined at this time.

On January 18, 2013, the Company filed its annual PEP filing for 2013, which indicated a rate increase of 1.990%, or $15.8 million, annually.

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

Environmental Compliance Overview Plan

In November 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. In December 2011, an order was issued 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.

On February 14, 2012, the Company submitted its 2012 ECO Plan filing, which proposed a 0.3% increase in annual revenues for the Company. In compliance with the CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2, the Company revised the 2012 ECO Plan filing to exclude scrubber expenditures from rate base, which resulted in a 0.16% decrease in annual revenues. On June 22, 2012, the 2012 ECO Plan filing, including the proposed rate decrease, was approved by the Mississippi PSC, effective on June 29, 2012.

On April 3, 2012, the Mississippi PSC approved the Company's request for a CPCN to construct a scrubber on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi (Chancery Court). 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, excluding AFUDC. The project is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the ECO Plan. As of December 31, 2012, total project expenditures were $146.6 million, with the Company's portion being $73.3 million.

On February 12, 2013, the Company submitted its 2013 ECO Plan filing, which proposed no change in rates.

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

Certificated New Plant

See "Integrated Coal Gasification Combined Cycle" for information on certificated new plant and the Company's cost recovery plans.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. On January 18, 2013, in compliance with the Company's filing requirement, the Company requested an annual adjustment of the retail fuel cost recovery factor in an amount equal to a decrease of 4.7% of total 2012 retail revenue. At December 31, 2012, the amount of over recovered retail fuel costs included in the balance sheets was $56.6 million compared to $42.4 million at December 31, 2011. The Company also has a wholesale Municipal and Rural Associations (MRA) and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2013, the wholesale MRA fuel rate decreased resulting in an annual decrease in an amount equal to 3.3% of total 2012 MRA revenue. Effective February 1, 2013, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 5.5% of total 2012 MB revenue. At December 31, 2012, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $19.0 million and $2.1 million compared to $14.3 million and $2.2 million, respectively, at December 31, 2011. In addition, at December 31, 2012, the amount of over recovered MRA emissions allowance cost included in the balance sheets was $0.4 million compared to $1.7 million at December 31, 2011. 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, changes in the billing factor have no significant effect on the Company's revenues or net income, but will affect annual cash flow.

In March 2011, a portion of the Company's territorial wholesale loads that was formerly served under the MB tariff terminated service. Beginning in April 2011, a new power purchase agreement (PPA) went into effect to cover these MB customers as non-territorial load. In June 2011, the Company and 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 in June 2011. See "Other Matters" herein for additional information.

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). The 2012 audit of fuel-related expenditures began in the second quarter 2012 and was completed in the fourth quarter 2012 with no audit findings.

Storm Damage Cost Recovery

In August 2012, Hurricane Isaac hit the Gulf Coast of the United States and caused damage within the Company's service area. The estimated total storm restoration costs relating to Hurricane Isaac through December 31, 2012 were $10.5 million. The Company maintains a reserve to cover the cost of damage from major storms to its transmission and distribution facilities and generally the cost of uninsured damage to its generation facilities and other property. At December 31, 2012, the balance in the storm reserve was $58.8 million.

Income Tax Matters

Bonus Depreciation

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014), which is expected to apply to the Kemper IGCC scheduled to be placed in service in May 2014.

Due to the significant amount of estimated bonus depreciation for 2013, the utilization of a portion of the Company's tax credits has been delayed. See "Integrated Coal Gasification Combined Cycle – Tax Incentives" for additional information.

Integrated Coal Gasification Combined Cycle

General

The Company is constructing the Kemper IGCC which will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will use as fuel locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. In connection with the Kemper IGCC, the Company also plans to construct and operate approximately 61 miles of carbon dioxide (CO_2) pipeline infrastructure. The Kemper IGCC is scheduled to be placed in-service in May 2014.

In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC (2010 MPSC Order). The Sierra Club filed an appeal of the Mississippi PSC's issuance of the CPCN and, on March 15, 2012, the Mississippi Supreme Court reversed the decision of the Chancery Court of Harrison County Mississippi (Chancery Court) upholding the 2010 MPSC Order and remanded the matter to the Mississippi PSC. The Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN. On March 30, 2012, the Mississippi PSC issued a temporary authorization which allowed the Company to continue construction and, on April 24, 2012, issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC. On April 26, 2012, the Sierra Club appealed the 2012 MPSC Order to the Chancery Court. On December 17, 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court.

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245.3 million of grants awarded to the project by the United States Department of Energy (DOE) under the Clean Coal Power Initiative Round 2 (CCPI2) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and financing costs related to the Kemper IGCC. The 2012 MPSC Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. Exemptions from the cost cap included in the 2012 MPSC Order included the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when the Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on the ratepayers, relative to the original proposal for the CPCN).

The Company's current cost estimate for the Kemper IGCC (net of the $245.3 million CCPI2 grant, and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement that must be specifically approved by the Mississippi PSC) is approximately $2.88 billion. The Mississippi PSC and the MPUS have engaged their independent monitors to assess the current cost estimates and schedule projections for the Kemper IGCC. These consultants have issued reports with their own opinions as to the likelihood that costs for the Kemper IGCC will remain at or under the $2.88 billion cost cap and as to the expected in-service date. While the Company continues to believe its cost estimate and schedule projection remain appropriate based on the current status of the project, it is possible that the Company could experience further cost increases and/or schedule delays with respect to the Kemper IGCC. Certain factors have caused and may continue to cause the costs for the Kemper IGCC to increase and/or schedule delays to occur including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, and unforeseen engineering problems. To the extent it becomes probable that costs beyond any permitted exceptions to the cost cap will exceed $2.88 billion or it becomes probable that the Mississippi PSC will disallow a portion of the costs relating to the Kemper IGCC, including certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement, charges to expense may occur and these charges could be material. See "Cost Recovery Plans" below for additional information relating to the Settlement Agreement that defines the process for resolving matters regarding cost recovery related to the Kemper IGCC.

As of December 31, 2012, the Company had spent a total of $2.51 billion on the Kemper IGCC, including the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and other deferred costs. Of this total, $2.47 billion was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $34.9 million was recorded in other regulatory assets, $3.8 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed. 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. 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.

The 2012 MPSC Order established periodic prudence reviews during the annual CWIP review process. Of the total costs of $51 million incurred through March 2009, $46 million has been reviewed and deemed prudent by the Mississippi PSC. Due to the decision of the Mississippi PSC to deny the CNP-A rate filing and a 2012 rate request related to the Kemper IGCC described below, prudence reviews for the construction costs of the Kemper IGCC incurred after March 2009 have not been made. The Settlement Agreement provides for completion of all prudence reviews within six months of the date the Kemper IGCC is placed in service. See "Cost Recovery Plans" herein for additional information.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Cost Recovery Plans

The 2012 MPSC Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. In the 2012 MPSC Order, the Mississippi PSC approved financing cost recovery on CWIP balances not to exceed the $2.4 billion certificated cost estimate for the Kemper IGCC. The 2012 MPSC Order provided for the accrual of AFUDC in 2010 and 2011 and for the current recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of financing cost recovery allowed is to be reduced by the amount of certain state and federal government construction cost incentives received by the Company and must be justified by a showing that such recovery will benefit customers over the life of the Kemper IGCC). With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN.

On June 1, 2012, the MPUS signed a joint stipulation with the Company to establish a proposed rate schedule detailing CNP-A and, on June 14, 2012, the Company submitted to the Mississippi PSC a filing to establish the new CNP-A rate schedule and a stipulated rate increase based upon the revenue request of between $55.3 million and $58.6 million to recover financing costs over the remainder of 2012. On June 22, 2012, the Mississippi PSC denied the proposed CNP-A rate schedule and the 2012 rate recovery filings submitted by the Company, pending a final ruling from the Mississippi Supreme Court regarding the Sierra Club's appeal of the Mississippi PSC's issuance of the CPCN for the Kemper IGCC.

On July 9, 2012, the Company appealed the Mississippi PSC's June 22, 2012 decision to the Mississippi Supreme Court and requested interim rates under bond of $55.3 million. On July 31, 2012, the Mississippi Supreme Court denied the Company's request for interim rates under bond until the Mississippi Supreme Court decides the Company's appeal of the Mississippi PSC's June 22, 2012 decision.

On January 24, 2013, the Company and the Mississippi PSC entered into the Settlement Agreement that (1) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to the Company and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (2) resolves the Company's CNP-A rate appeal before the Mississippi Supreme Court.

On February 12, 2013, the Mississippi Supreme Court granted the Company and the Mississippi PSC's joint filing for dismissal of the Company's appeal of the Mississippi PSC's June 22, 2012 decision.

Under the terms of the Settlement Agreement, the Company and the Mississippi PSC will follow certain agreed-upon regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) the Company's filing within 30 days of the Settlement Agreement of a new request to increase rates in 2013 in an amount not to exceed a $172 million annual revenue requirement, based upon projected investment as of December 31, 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service (which filing for $172 million was made on January 25, 2013); (2) the Mississippi PSC's decision on that matter within 50 days of the Company's request; (3) the Company's collaboration with the MPUS to file with the Mississippi PSC within three months of the Settlement Agreement a rate recovery plan for the Kemper IGCC for the first seven years of its operation, along with a proposed revenue requirement under such plan for 2014 through 2020 (which filing was made on February 26, 2013 as described below); (4) the Mississippi PSC's decision on the rate recovery plan within four months of that filing; (5) the Company's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated cost estimate, plus costs related to the lignite mine and CO_2 pipeline as well as any other costs permitted or determined to be excluded from the cost cap, provided that this limitation will not prevent the Company from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the seven-year rate plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was passed in the Mississippi legislature and was signed by the Governor on February 26, 2013. The Company contemplates using securitization as provided in the legislation as its form of alternate financing for prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement.

On February 26, 2013, the Company, in compliance with the Settlement Agreement, filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The rate recovery plan proposes recovery of an annual revenue requirement of approximately $150 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. Approval of the Company's request to increase rates in 2013 to mitigate the rate impacts of the Kemper IGCC filed on January 25, 2013 is integral to the rate recovery plan as the proposed filing contemplates amortization of the regulatory liability to be used to mitigate rate impacts from 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the rate recovery plan filing, the Company proposes annual recovery to remain the same from 2014 through 2020 and while it is the intent of the Company for the actual revenue requirement to equal the proposed revenue requirement for certain items, the Company proposes that the annual differences for those items through 2020 will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC for determination of the manner of recovery. The Company proposes to secure recovery of prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement to be provided for with alternate financing through securitization. The rate recovery necessary to recover the annual costs of securitization is proposed to be filed and begin after the Kemper IGCC is placed in service.

Under the terms of the Settlement Agreement, the Company has the right to terminate the Settlement Agreement if certain conditions, including the passage of multi-year rate plan legislation that is contemplated under the Settlement Agreement, are not met, if the Company is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Tax Incentives

The Internal Revenue Service (IRS) has allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. The Company's 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 Kemper IGCC during operations in accordance with the rules for Section 48A investment tax credits. Through December 31, 2012, the Company received or accrued tax benefits totaling $361.6 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 bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $170.9 million of these tax credits until after 2013. IRS guidelines allow these unused tax credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then. On October 15, 2012, the Company filed an application with the DOE for certification of the Kemper IGCC for additional tax credits under the Internal Revenue Code Section 48A (Phase III). A portion of the tax credits realized by the Company may be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described below. In addition, all or a portion of the tax credits will be subject to recapture if the Company fails to satisfy the in-service date requirements and carbon capture requirements described above. See "Income Tax Matters" herein for additional information.

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

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site in Kemper County. The mine is scheduled to be placed in-service in June 2013. The estimated capital cost of the mine is approximately $245 million, of which $163.3 million has been incurred through December 31, 2012.

In 2010, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC, a wholly-owned subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, the Company will acquire, construct, and operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The estimated capital cost of the CO_2 pipeline facilities is approximately $132 million, of which $78.4 million has been incurred through December 31, 2012.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. On February 28, 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On June 29, 2012, the Company and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012 and reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC, subject to approval by the Mississippi PSC. On December 31, 2012, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013.

The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. On September 27, 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

On March 6, 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, the Company would be required to refund the deposit upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that the Company is assigned a senior unsecured credit rating of BBB+ or lower by Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc. (S&P) or Baa1 or lower by Moody's Investors Services, Inc. (Moody's) or ceases to be rated by either of these rating agencies.

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

Baseload Act

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the

Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. There are legal challenges to the constitutionality of the Baseload Act currently pending before the Mississippi Supreme Court. The ultimate impact of this legislation will depend on the outcome of any legal challenges and cannot be determined at this time. See "Cost Recovery Plans" herein for additional information regarding certain legislation related to the Kemper IGCC.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by CO_2 and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

On February 6, 2013, the Company submitted a claim under the Deepwater Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in April 2010 in the Gulf of Mexico. The ultimate outcome of this matter cannot be determined at this time.

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 any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

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

Unbilled Revenues

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 $1.5 million or less change in total annual benefit expense and an $18.4 million or less change in projected obligations.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 7.04%, 7.06%, and 7.33% for the years ended December 31, 2012, 2011, and 2010, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC, net of income taxes, as a percentage of net income after dividends on preferred stock was 57.05%, 31.60%, and 6.97% for 2012, 2011, and 2010, respectively.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2013 through 2015, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan increased in value as of December 31, 2012 as compared to December 31, 2011. In December 2012, the Company contributed $43.0 million to the qualified pension plan.

Net cash provided from operating activities totaled $235.4 million for 2012, an increase of $3.9 million as compared to the corresponding period in 2011. The increase in net cash provided from operating activities was primarily due to an increase in investment tax credits received related to the Kemper IGCC and an increase in over recovered regulatory clause revenues. The increase in cash provided from operating activities was partially offset by a contribution to the qualified pension plan in 2012, payments for fuel stock, and the settlement of interest rate swaps. Net cash provided from operating activities in 2011 totaled $231.5 million, an increase of $98.8 million compared to 2010. The increase in net cash provided from operating activities was primarily due to a decrease in the use of funds related to the Kemper IGCC generation construction screening costs incurred during 2010, cash payment made in 2010 to fund the qualified pension plan, and a decrease in prepaid income taxes. These increases in cash provided from operating activities were partially offset by a decrease in over recovered regulatory clause revenues and a decrease in fossil fuel stock.

Net cash used for investing activities totaled $1.5 billion for 2012 primarily due to an increase in property additions primarily related to the Kemper IGCC, partially offset by a decrease in restricted cash, a decrease in capital grant proceeds received primarily related to CCPI2 and Smart Grid Investment grants, and a decrease in plant acquisition due to the cash payment associated with the purchase of Plant Daniel Units 3 and 4 in 2011. Net cash used for investing activities in 2011 totaled $682.7 million primarily due to an increase in property additions primarily related to the Kemper IGCC and an increase in plant acquisition 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 an increase in construction payables, a change in restricted cash associated with the second series revenue bonds issued in 2010, and an increase in capital grant proceeds received primarily related to CCPI2 and Smart Grid Investment grants.

Net cash provided from financing activities totaled $1.2 billion in 2012 primarily due to an increase in capital contributions from Southern Company, an increase in long-term debt financings and the receipt of an interest bearing refundable deposit related to a pending asset sale, partially offset by redemptions of long-term debt financings. Net cash provided from financing activities totaled $502.0 million in 2011 primarily due to an increase in capital contributions from Southern Company, an increase in long-term debt, and redemptions of long-term debt financings.

Significant changes in the balance sheet as of December 31, 2012 compared to 2011 include an increase in prepaid income taxes of $92.0 million and an increase in accumulated deferred investment tax credits of $260.8 million primarily due to the Kemper IGCC investment tax credit. Total property, plant, and equipment increased $1.6 billion primarily due to the increase in CWIP related to the Kemper IGCC. Interest-bearing refundable deposit related to an asset sale increased $150.0 million due to the receipt of the $150.0 million interest-bearing refundable deposit from SMEPA. Long-term debt increased $460.9 million primarily due to the issuance of $600.0 million of senior notes, partially offset by the redemption of $90.0 million of senior notes and the reclassification of a $50.0 million long-term bank loan maturing in November 2013. Common stockholder's equity increased $748.2 million primarily due to the increase in paid-in capital due to $700.0 million in capital contributions from Southern Company in 2012.

The Company's ratio of common equity to total capitalization, excluding long-term debt due within one year, increased from 48.0% in 2011 to 52.9% at December 31, 2012.

Sources of Capital

Except as described herein, 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 debt, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. In 2012, the Company received $700 million in capital contributions from Southern Company. On January 31, 2013, the Company received $100 million in additional capital contributions from Southern Company. See "Capital Requirements and Contractual Obligations" herein for additional information.

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. On January 29, 2013, the Company withdrew its application for federal loan guarantees related to the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

Investment tax credits related to the Kemper IGCC of $170.9 million are not expected to be utilized until after 2013, 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 raising capital.

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

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

At December 31, 2012, the Company had approximately $145.0 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[(a)]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
		(in millions)					
$ 135	$ 165	$ 300	$ 300	$ 25	$ 40	$ 65	$ 70

(a) No credit arrangements expire after 2014.

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

Most of these arrangements contain covenants that limit debt levels and typically contain cross-default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants. The Company expects to renew its credit arrangements, as needed prior to expiration.

These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2012 was $40.1 million.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional operating 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, 2012:					
Commercial paper	$ —	—%	$ —	—%	$ —
December 31, 2011:					
Commercial paper	$ —	—%	$ 7	0.2%	$ 70
December 31, 2010:					
Commercial paper	$ —	—%	$ 12	0.3%	$ 63

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

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

Financing Activities

In 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.

Bank Term Loans

In March 2012, the Company paid at maturity a $75 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month London Interbank Offered Rate (LIBOR).

In September 2012, the Company paid at maturity a $40 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month LIBOR.

In November 2012, the Company entered into a 366-day $100 million aggregate principal amount floating rate term loan agreement that bears interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used solely for working capital and other general corporate purposes, including the Company's continuous construction program.

Senior Notes

In March 2012, the Company issued $250 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042 and an additional $150 million aggregate principal amount of Series 2011A 2.35% Senior Notes due October 15, 2016. The Series 2011A Senior Notes were of the same series of notes that were originally issued in October 2011 in the aggregate principal amount of $150 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2011A Senior Notes was $300 million. The proceeds from the sales of the Series 2012A Senior Notes and the Series 2011A Senior Notes were used to repay a bank term loan in an aggregate principal amount of $75 million, bearing interest at a variable rate based on one-month LIBOR, and for general corporate purposes, including the Company's continuous construction program.

In March 2012, $300 million in interest rate swaps were settled, of which $250 million related to the Series 2012A Senior Notes at a loss of approximately $13.3 million, which will be amortized to interest expense, in earnings, over 10 years, and $50 million related to the Series 2011A Senior Notes at a loss of approximately $2.7 million, which will be amortized to interest expense, in earnings, over 10 years.

In May 2012, the Company redeemed $90 million aggregate principal amount of Series E 5-5/8% Senior Notes due May 1, 2033.

In August 2012, the Company issued an additional $200 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042. The Series 2012A Senior Notes were of the same series of notes that were originally issued in March 2012 in the aggregate principal amount of $250 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2012A Senior Notes is $450 million. The proceeds from this sale of the Series 2012A Senior Notes were used for general corporate purposes, including the Company's continuous construction program.

Other Revenue Bonds

In August 2012, the Mississippi Business Finance Corporation (MBFC) entered into an agreement to issue up to $42.50 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012A (Mississippi Power Company Project), up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012B (Mississippi Power Company Project), and up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012C (Mississippi Power Company Project) for the benefit of the Company. During 2012, the MBFC issued $8.97 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A, $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012B, and $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012C for the benefit of the Company. The proceeds were used to reimburse the Company for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. Any future issuances of the Series 2012A bonds will be used for this same purpose.

Other Obligations

In March 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at the Company's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that the Company is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies.

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 Plant Daniel Units 3 and 4. In October 2011, the Company purchased Plant Daniel Units 3 and 4 for $84.8 million in cash and the assumption of $270.0 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 were 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 in July 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 November 2011, the Company filed a request with the FERC seeking the same accounting and regulatory treatment for its wholesale cost-based jurisdiction. The total amount deferred in other regulatory assets, deferred at December 31, 2012 was $12.4 million. 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, 2012, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $273 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 and the variable rate pollution control revenue bond market.

In March 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at the Company's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that the Company is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies.

On July 3, 2012, Fitch downgraded the issuer default and unsecured long-term debt ratings of the Company to A- from A and to A from A+, respectively. Fitch also announced that it had downgraded the pollution control revenue bond ratings of the Company to A from A+ and the preferred stock ratings of the Company to BBB+ from A-. Fitch revised the ratings outlook for the Company to negative from stable.

On August 6, 2012, Moody's downgraded the senior unsecured debt and preferred stock ratings of the Company to A3 from A2 and to Baa2 from Baa1, respectively. Moody's revised the ratings outlook for the Company to negative from stable.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $266.5 million of outstanding variable rate long-term debt at December 31, 2012 was 0.72%. 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 $2.7 million at January 1, 2013. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage retail fuel hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel hedging programs under agreements with wholesale customers. The Company had no material change in market risk exposure for the year ended December 31, 2012 when compared to the December 31, 2011 reporting period.

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

	2012 Changes	2011 Changes
	Fair Value	
	(in thousands)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (50,990)**	$ (43,770)
Contracts realized or settled	**43,326**	32,381
Current period changes[(a)]	**(9,263)**	(39,601)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (16,927)**	$ (50,990)

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

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

	2012 Changes	2011 Changes
	Fair Value	
	(in thousands)	
Natural gas swaps	**$ 26,020**	$ 1,066
Natural gas options	**8,085**	(8,286)
Other energy related derivatives	**(42)**	—
Total changes	**$ 34,063**	$ (7,220)

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

	2012	2011
	mmBtu* Volume	
	(in thousand)	
Commodity – Natural gas swaps	**38,130**	21,660
Commodity – Natural gas options	**—**	9,350
Total hedge volume	**38,130**	31,010

* million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.44 per mmBtu as of December 31, 2012 and $1.98 per mmBtu as of December 31, 2011. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The costs associated with natural gas hedges are recovered through the Company's energy cost management clauses.

At December 31, 2012 and 2011, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the 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 and 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 2013.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2012 were as follows:

Fair Value Measurements
December 31, 2012

	Total Fair Value	Maturity Year 1	Years 2&3	Years 4&5
		(in thousands)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(16,927)	(12,478)	(4,730)	281
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (16,927)	$ (12,478)	$ (4,730)	$ 281

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

Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. Included in the estimated base level capital investment amounts are expenditures related to the construction of the Kemper IGCC of $513 million and $218 million in 2013 and 2014, respectively, which are net of SMEPA's 15% proposed ownership share of the construction of the Kemper IGCC of approximately $492 million and $28 million in 2013 and 2014, respectively. The estimated share for SMEPA in 2013 reflects estimated construction costs relating to SMEPA's proposed ownership interest to be incurred through December 31, 2013 (including construction costs for all prior years relating to its proposed ownership interest). These estimated base level capital investment amounts also include capital expenditures covered under LTSAs, as well as capital expenditures and compliance costs associated with the MATS rule. Proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment.

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

	2013	2014	2015
Construction program:		*(in millions)*	
Base capital	$ 667	$ 324	$ 139
Existing environmental statutes and regulations, including the MATS rule	129	174	116
Total construction program base level capital investment	**$ 796**	**$ 498**	**$ 255**
Potential incremental environmental compliance investment:			
Proposed water and coal combustion byproducts rules	$ —	$ 6	$ 28

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and – "Integrated Coal Gasification Combined Cycle" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in the expected environmental compliance program; 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

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing [d]	Total
			(in thousands)			
Long-term debt[a] —						
Principal	$ 276,471	$ —	$ 335,000	$ 1,157,695	$ —	$ 1,769,166
Interest	71,290	132,879	125,829	819,619	—	1,149,617
Preferred stock dividends[b]	1,733	3,465	3,465	—	—	8,663
Financial derivative obligations[c]	13,116	6,202	165	—	—	19,483
Unrecognized tax benefits[d]	3,562	—	—	—	3,997	7,559
Operating leases [e]	11,232	11,648	1,920	—	—	24,800
Purchase commitments —						
Capital[f]	757,037	752,522	—	—	—	1,509,559
Fuel[g]	349,197	378,355	176,500	159,221	—	1,063,273
Long-term service agreements[h]	21,032	43,893	17,148	—	—	82,073
Pension and other postretirement benefits plans[i]	5,602	12,172	—	—	—	17,774
Total	$ 1,510,272	$ 1,341,136	$ 660,027	$ 2,136,535	$ 3,997	$ 5,651,967

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2013, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts.

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

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

(d) The timing related to the realization of $4.0 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) See Note 7 to the financial statements for additional information.

(f) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion byproducts rules, which are approximately $6 million and $28 million for years 2014 and 2015, respectively. Estimates reflect the proposed sale of 15% of the Kemper IGCC to SMEPA. At December 31, 2012, significant purchase commitments were outstanding in connection with the construction program. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected separately. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

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

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

(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, 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 Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, storm damage cost recovery and repairs, economic recovery, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including 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), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities, including the development and construction of facilities with designs that have not been finalized or previously constructed, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- 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 legislative actions related to the Kemper IGCC, including Mississippi PSC approvals and legislation relating to cost recovery for the Kemper IGCC, the SMEPA purchase decision, satisfaction of requirements to utilize investment tax credits and grants, and the outcome of any proceedings regarding the Mississippi PSC's issuance of the CPCN for the Kemper IGCC;
- 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.

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

	2012	2011	2010
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 747,453**	$ 792,463	$ 797,912
Wholesale revenues, non-affiliates	**255,557**	273,178	287,917
Wholesale revenues, affiliates	**16,403**	30,417	41,614
Other revenues	**16,583**	16,819	15,625
Total operating revenues	**1,035,996**	1,112,877	1,143,068
Operating Expenses:			
Fuel	**411,226**	490,415	501,830
Purchased power, non-affiliates	**5,221**	6,239	8,426
Purchased power, affiliates	**49,907**	65,574	75,230
Other operations and maintenance	**228,675**	266,395	268,063
Depreciation and amortization	**86,510**	80,337	76,891
Taxes other than income taxes	**79,445**	70,127	69,810
Total operating expenses	**860,984**	979,087	1,000,250
Operating Income	**175,012**	133,790	142,818
Other Income and (Expense):			
Allowance for equity funds used during construction	**64,793**	24,707	3,795
Interest income	**745**	1,347	215
Interest expense, net of amounts capitalized	**(40,838)**	(21,691)	(22,341)
Other income (expense), net	**519**	(45)	3,738
Total other income and (expense)	**25,219**	4,318	(14,593)
Earnings Before Income Taxes	**200,231**	138,108	128,225
Income taxes	**50,391**	42,193	46,275
Net Income	**149,840**	95,915	81,950
Dividends on Preferred Stock	**1,733**	1,733	1,733
Net Income After Dividends on Preferred Stock	**$ 148,107**	$ 94,182	$ 80,217

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

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

	2012	2011	2010
		(in thousands)	
Net Income	**$ 149,840**	$ 95,915	$ 81,950
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(296), $(5,494), and $1, respectively	**(479)**	(8,870)	2
Reclassification adjustment for amounts included in net income, net of tax of $411, $(18), and $-, respectively	**663**	(29)	—
Total other comprehensive income (loss)	**184**	(8,899)	2
Comprehensive Income	**$ 150,024**	$ 87,016	$ 81,952

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

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

	2012	2011	2010
		(in thousands)	
Operating Activities:			
Net income	$ **149,840**	$ 95,915	$ 81,950
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**86,981**	83,787	82,294
Deferred income taxes	**47,523**	71,764	37,557
Investment tax credits received	**82,464**	—	22,173
Allowance for equity funds used during construction	**(64,793)**	(24,707)	(3,795)
Pension, postretirement, and other employee benefits	**(35,425)**	3,169	(34,911)
Hedge settlements	**(15,983)**	848	—
Stock based compensation expense	**2,084**	1,548	1,186
Generation construction screening costs	—	—	(50,554)
Regulatory assets associated with Kemper IGCC	**(15,445)**	(7,719)	(12,292)
Other, net	**10,516**	(433)	8,888
Changes in certain current assets and liabilities —			
-Receivables	**(6,589)**	5,864	(8,185)
-Fossil fuel stock	**(36,206)**	(27,933)	14,997
-Materials and supplies	**(3,473)**	(2,116)	(879)
-Prepaid income taxes	**(3,852)**	12,907	(17,075)
-Other current assets	**(19,851)**	1,606	(4,633)
-Other accounts payable	**8,814**	24,143	(12,630)
-Accrued interest	**17,627**	6,817	194
-Accrued taxes	**13,768**	1,209	(4,268)
-Accrued compensation	**(183)**	(187)	2,291
-Over recovered regulatory clause revenues	**16,836**	(16,544)	28,450
-Other current liabilities	**757**	1,557	1,943
Net cash provided from operating activities	**235,410**	231,495	132,701
Investing Activities:			
Property additions	**(1,620,047)**	(964,233)	(247,005)
Plant acquisition	—	(84,803)	—
Investment in restricted cash	—	—	(50,000)
Distribution of restricted cash	—	50,000	—
Cost of removal net of salvage	**(4,355)**	(7,432)	(9,240)
Construction payables	**78,961**	97,079	33,767
Capital grant proceeds	**13,372**	232,442	23,657
Other investing activities	**(16,706)**	(5,736)	(5,587)
Net cash used for investing activities	**(1,548,775)**	(682,683)	(254,408)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	**702,971**	299,305	65,215
Bonds-Other	**51,471**	—	—
Senior notes issuances	**600,000**	300,000	—
Interest-bearing refundable deposit related to asset sale	**150,000**	—	—
Other long-term debt issuances	**50,000**	115,000	225,000
Redemptions —			
Capital leases	**(633)**	(1,437)	(1,330)
Senior notes	**(90,000)**	—	—
Other long-term debt	**(115,000)**	(130,000)	—
Payment of preferred stock dividends	**(1,733)**	(1,733)	(1,733)
Payment of common stock dividends	**(106,800)**	(75,500)	(68,600)
Other financing activities	**6,512**	(3,641)	(1,091)
Net cash provided from (used for) financing activities	**1,246,788**	501,994	217,461
Net Change in Cash and Cash Equivalents	**(66,577)**	50,806	95,754
Cash and Cash Equivalents at Beginning of Year	**211,585**	160,779	65,025
Cash and Cash Equivalents at End of Year	$ **145,008**	$ 211,585	$ 160,779
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $32,816, $10,065 and $2,903 capitalized, respectively)	$ **32,589**	$ 14,814	$ 19,518
Income taxes (net of refunds)	**(77,580)**	(41,024)	7,546
Noncash transactions — accrued property additions at year-end	**214,863**	135,902	37,736
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, 2012 and 2011
Mississippi Power Company 2012 Annual Report

Assets	**2012**	2011
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 145,008**	$ 211,585
Receivables —		
Customer accounts receivable	**29,561**	32,551
Unbilled revenues	**32,688**	27,239
Other accounts and notes receivable	**7,517**	7,080
Affiliated companies	**27,160**	23,078
Accumulated provision for uncollectible accounts	**(373)**	(547)
Fossil fuel stock, at average cost	**176,378**	140,173
Materials and supplies, at average cost	**34,260**	30,787
Other regulatory assets, current	**55,302**	69,201
Prepaid income taxes	**129,835**	37,793
Other current assets	**17,170**	8,881
Total current assets	**654,506**	587,821
Property, Plant, and Equipment:		
In service	**3,036,159**	2,902,240
Less accumulated provision for depreciation	**1,065,474**	1,019,251
Plant in service, net of depreciation	**1,970,685**	1,882,989
Construction work in progress	**2,471,145**	955,135
Total property, plant, and equipment	**4,441,830**	2,838,124
Other Property and Investments	**4,887**	6,520
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**71,869**	25,009
Other regulatory assets, deferred	**236,225**	185,694
Other deferred charges and assets	**42,304**	28,674
Total deferred charges and other assets	**350,398**	239,377
Total Assets	**$ 5,451,621**	$ 3,671,842

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

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

Liabilities and Stockholder's Equity		2012		2011
		(in thousands)		
Current Liabilities:				
Securities due within one year	$	276,471	$	240,633
Interest-bearing refundable deposit related to asset sale		150,000		—
Accounts payable —				
Affiliated		54,769		62,650
Other		262,992		168,309
Customer deposits		14,202		13,658
Accrued taxes —				
Accrued income taxes		2,339		3,813
Other accrued taxes		69,376		53,825
Accrued interest		30,376		12,750
Accrued compensation		15,706		15,889
Other regulatory liabilities, current		5,376		5,779
Over recovered regulatory clause liabilities		77,338		60,502
Liabilities from risk management activities		13,116		54,127
Other current liabilities		18,766		17,533
Total current liabilities		990,827		709,468
Long-Term Debt (See accompanying statements)		1,564,462		1,103,596
Deferred Credits and Other Liabilities:				
Accumulated deferred income taxes		274,793		270,397
Deferred credits related to income taxes		10,106		11,058
Accumulated deferred investment tax credits		370,554		109,761
Employee benefit obligations		157,421		161,065
Other cost of removal obligations		143,461		126,424
Other regulatory liabilities, deferred		56,984		60,848
Other deferred credits and liabilities		52,860		37,228
Total deferred credits and other liabilities		1,066,179		776,781
Total Liabilities		3,621,468		2,589,845
Cumulative Redeemable Preferred Stock (See accompanying statements)		32,780		32,780
Common Stockholder's Equity (See accompanying statements)		1,797,373		1,049,217
Total Liabilities and Stockholder's Equity	$	5,451,621	$	3,671,842
Commitments and Contingent Matters (See notes)				

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

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

	2012	2011	**2012**	2011
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
6.00% due 2013	**$ 50,000**	$ 50,000		
2.35% due 2016	**300,000**	150,000		
5.60% due 2017	**35,000**	35,000		
2.25% to 5.63% due 2019-2042	**805,000**	445,000		
Adjustable rates (0.60% to 0.85% at 1/1/12) due 2012	**—**	240,000		
Adjustable rates (0.63% to 1.21% at 1/1/13) due 2013	**226,471**	—		
Total long-term notes payable	**1,416,471**	920,000		
Other long-term debt —				
Pollution control revenue bonds:				
5.15% due 2028	**42,625**	42,625		
Variable rates (0.12% to 0.14% at 1/1/13) due 2020-2028	**40,070**	40,070		
Plant Daniel revenue bonds (7.13%) due 2021	**270,000**	270,000		
Total other long-term debt	**352,695**	352,695		
Capitalized lease obligations	**—**	633		
Unamortized debt premium	**80,912**	74,551		
Unamortized debt discount	**(9,145)**	(3,650)		
Total long-term debt (annual interest requirement — $71.3 million)	**1,840,933**	1,344,229		
Less amount due within one year	**276,471**	240,633		
Long-term debt excluding amount due within one year	**1,564,462**	1,103,596	**46.1%**	50.5%
Cumulative Redeemable Preferred Stock:				
$100 par value				
Authorized: 1,244,139 shares				
Outstanding: 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $1.7 million)	**32,780**	32,780	**1.0**	1.5
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized: 1,130,000 shares				
Outstanding: 1,121,000 shares	**37,691**	37,691		
Paid-in capital	**1,401,520**	694,855		
Retained earnings	**366,875**	325,568		
Accumulated other comprehensive income (loss)	**(8,713)**	(8,897)		
Total common stockholder's equity	**1,797,373**	1,049,217	**52.9**	48.0
Total Capitalization	**$ 3,394,615**	$ 2,185,593	**100.0%**	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
Mississippi Power Company 2012 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in thousands)		
Balance at December 31, 2009	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**
Net income after dividends on preferred stock	**—**	**—**	**—**	**148,107**	**—**	**148,107**
Capital contributions from parent company	**—**	**—**	**706,665**	**—**	**—**	**706,665**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**184**	**184**
Cash dividends on common stock	**—**	**—**	**—**	**(106,800)**	**—**	**(106,800)**
Balance at December 31, 2012	**1,121**	**$ 37,691**	**$1,401,520**	**$366,875**	**$ (8,713)**	**$1,797,373**

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 the Company and three other traditional operating companies, as well as Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – 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 the Southern Company system's nuclear power plants.

The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities (VIEs) 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 $212.7 million, $185.5 million, and $125.1 million during 2012, 2011, and 2010, respectively. The increase in 2012 and 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 the construction of a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has 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 non-fuel expenditures and costs, which totaled $11.7 million, $12.2 million, and $11.2 million in 2012, 2011, and 2010, respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility, which were $28.1 million in 2012, $20.9 million in 2011, and $16.1 million in 2010. 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 $21.2 million, $23.3 million, and $25.0 million in 2012, 2011, and 2010, respectively. See Note 4 for additional information.

The Company also provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2011 and 2010. The Company received storm assistance from other Southern Company subsidiaries totaling $2.0 million in 2012. There was no significant storm assistance received from affiliates in 2011 or 2010.

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

New Accounting Pronouncements

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

Regulatory Assets and Liabilities

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

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

	2012	2011	Note
		(in thousands)	
Retiree benefit plans	**$ 162,293**	$ 130,678	(a,g)
Property damage	**(58,789)**	(64,748)	(i)
Deferred income tax charges	**68,175**	21,000	(c)
Property tax	**27,882**	18,484	(d)
Vacation pay	**9,635**	9,128	(e,g)
Loss on reacquired debt	**9,815**	7,171	(k)
Plant Daniel Units 3 and 4 regulatory assets	**12,386**	3,945	(j)
Other regulatory assets	**2,035**	132	(b)
Fuel hedging (realized and unrealized) losses	**20,906**	54,103	(f,g)
Asset retirement obligations	**9,353**	9,057	(c)
Deferred income tax credits	**(11,157)**	(12,081)	(c)
Other cost of removal obligations	**(143,461)**	(126,424)	(c)
Fuel hedging (realized and unrealized) gains	**(2,519)**	(162)	(f,g)
Kemper IGCC regulatory assets	**36,047**	20,684	(h)
Other regulatory liabilities	**—**	(693)	(b)
Deferred income tax charges — Medicare subsidy	**4,868**	5,521	(l)
Total regulatory assets (liabilities), net	**$ 147,469**	$ 75,795	

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

(a) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

(b) Recorded and recovered as approved by the Mississippi PSC.

(c) Asset retirement and removal assets and liabilities and deferred income tax assets are recovered, and removal assets and deferred income tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(d) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year.

(e) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(f) 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).

(g) Not earning a return as offset in rate base by a corresponding asset or liability.

(h) For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle."

(i) For additional information, see Note 1 under "Provision for Property Damage" and Note 3 under "Retail Regulatory Matters – System Restoration Rider."

(j) 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.

(k) Recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.

(l) 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.

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 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270.0 million of the Kemper IGCC through the CCPI2 funds. Through December 31, 2012, 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 $25.0 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 serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 22% of the Company's total operating revenues in 2012 and are largely subject to rolling 10-year cancellation notices.

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 where recovery of construction work in progress (CWIP) is not allowed in rates.

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

	2012	2011
	(in thousands)	
Generation	**$ 1,363,269**	$ 1,362,567
Transmission	**563,037**	497,202
Distribution	**802,718**	784,655
General	**225,723**	176,408
Plant acquisition adjustment	**81,412**	81,408
Total plant in service	**$ 3,036,159**	$ 2,902,240

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expense 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 the combined cycle generating Units 3 and 4 at Plant Daniel (Plant Daniel Units 3 and 4). In October 2011, the Company purchased Plant Daniel Units 3 and 4 for $84.8 million in cash and the assumption of $270.0 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 were reflected in the Company's financial statements as follows:

	(in thousands)
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 3.5% in 2012, 3.9% in 2011, and 3.4% in 2010. 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 2010, the Mississippi PSC issued an order approving the depreciation rates effective in 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 is being 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 in 2007 and recover them evenly over a four-year period beginning in 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 (ARO) 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, mine reclamation, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Mississippi PSC, and are reflected in the balance sheets.

Details of the ARO included in the balance sheets are as follows:

	2012	2011
	(in thousands)	
Balance at beginning of year	**$ 19,148**	$ 18,601
Liabilities incurred	**20,989**	137
Liabilities settled	**(282)**	(644)
Accretion	**1,874**	1,054
Cash flow revisions	**386**	—
Balance at end of year	**$ 42,115**	$ 19,148

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 7.04%, 7.06%, and 7.33% for the years ended December 31, 2012, 2011, and 2010, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC, net of income taxes, as a percentage of net income after dividends on preferred stock was 57.05%, 31.60%, and 6.97% for 2012, 2011, and 2010, respectively.

Impairment of Long-Lived Assets and Intangibles

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

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 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 2012, 2011, and 2010, the Company made retail accruals of $3.5 million, $3.8 million, and $3.1 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 2012, 2011 and in 2010 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.

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, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, 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 foreign currency exchange hedges are booked as 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. The amounts related to derivatives on the cash flow statement are classified in the same category as the items being hedged. 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, 2012.

The Mississippi PSC has approved the Company's request to implement an ECM which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, certain changes in pension and other postretirement benefit plans, and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The 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 year ended 2011, Liberty Fuels did not have a material impact on the financial position and results of operations of the Company. For the year ended December 31, 2012, the VIE consolidation resulted in an ARO and an associated liability in the amounts of \$21.0 million and \$21.8 million, respectively. 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). In December 2012, the Company contributed \$43.0 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2013, 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 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.92% and 5.83%, respectively, and an annual salary increase of 4.18%.

	2012	2011	2010
Discount rate:			
Pension plans	**4.26%**	4.98%	5.51%
Other postretirement benefit plans	**4.04**	4.87	5.39
Annual salary increase	**3.59**	3.84	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.45	8.45
Other postretirement benefit plans	**6.96**	7.53	7.65

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

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

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

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2012 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in thousands)	
Benefit obligation	$ 6,000	$ (5,099)
Service and interest costs	316	(268)

Pension Plans

The total accumulated benefit obligation for the pension plans was $392 million at December 31, 2012 and $339 million at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ **369,680**	$ 330,315
Service cost	**9,416**	8,838
Interest cost	**18,019**	17,827
Benefits paid	**(14,949)**	(14,587)
Plan amendments	**—**	—
Actuarial loss	**50,387**	27,287
Balance at end of year	**432,553**	369,680
Change in plan assets		
Fair value of plan assets at beginning of year	**282,100**	283,698
Actual return on plan assets	**39,668**	10,805
Employer contributions	**44,930**	2,184
Benefits paid	**(14,949)**	(14,587)
Fair value of plan assets at end of year	**351,749**	282,100
Accrued liability	$ **(80,804)**	$ (87,580)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $400 million and $32 million, respectively. All pension plan assets are related to the qualified pension plan.

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

	2012	2011
	(in thousands)	
Other regulatory assets, deferred	$ **146,838**	$ 117,354
Other current liabilities	**(2,087)**	(1,652)
Employee benefit obligations	**(78,717)**	(85,928)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in thousands)	
Prior service cost	$ **5,261**	$ 6,570	$ **1,143**
Net (gain) loss	**141,577**	110,784	**9,461**
Other regulatory assets, deferred	$ **146,838**	$ 117,354	

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

	Regulatory Assets
	(in thousands)
Balance at December 31, 2010	$ 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
Net (gain) loss	**34,893**
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	**(1,309)**
Amortization of net gain (loss)	**(4,100)**
Total reclassification adjustments	**(5,409)**
Total change	**29,484**
Balance at December 31, 2012	**$ 146,838**

Components of net periodic pension cost were as follows:

	2012	2011	2010
		(in thousands)	
Service cost	**$ 9,416**	$ 8,838	$ 8,300
Interest cost	**18,019**	17,827	17,916
Expected return on plan assets	**(24,121)**	(25,166)	(21,451)
Recognized net (gain) loss	**4,100**	1,114	634
Net amortization	**1,309**	1,309	1,391
Net periodic pension cost	**$ 8,723**	$ 3,922	$ 6,790

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

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2013	$ 16,282
2014	17,121
2015	17,947
2016	18,886
2017	20,001
2018 to 2022	117,471

Other Postretirement Benefits

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

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 87,447**	$ 81,688
Service cost	**1,038**	1,012
Interest cost	**4,155**	4,292
Benefits paid	**(4,432)**	(4,094)
Actuarial loss	**3,166**	4,073
Plan amendments	**—**	—
Retiree drug subsidy	**409**	476
Balance at end of year	**91,783**	87,447
Change in plan assets		
Fair value of plan assets at beginning of year	**20,534**	20,955
Actual return on plan assets	**2,427**	720
Employer contributions	**3,052**	2,477
Benefits paid	**(4,023)**	(3,618)
Fair value of plan assets at end of year	**21,990**	20,534
Accrued liability	**$ (69,793)**	$ (66,913)

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

	2012	2011
	(in thousands)	
Other regulatory assets, deferred	**$ 15,454**	$ 13,324
Employee benefit obligations	**(69,793)**	(66,913)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in thousands)	
Prior service cost	**$ (2,498)**	$ (2,686)	**$ (188)**
Net (gain) loss	**17,952**	15,839	**659**
Transition obligation	**—**	171	**—**
Other regulatory assets, deferred	**$ 15,454**	$ 13,324	

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

	Regulatory Assets
	(in thousands)
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
Net (gain) loss	**2,600**
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	**(171)**
Amortization of prior service costs	**188**
Amortization of net gain (loss)	**(487)**
Total reclassification adjustments	**(470)**
Total change	**2,130**
Balance at December 31, 2012	**$ 15,454**

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

	2012	2011	2010
		(in thousands)	
Service cost	**$ 1,038**	$ 1,012	$ 1,305
Interest cost	**4,155**	4,292	4,763
Expected return on plan assets	**(1,552)**	(1,763)	(1,826)
Net amortization	**470**	274	574
Net postretirement cost	**$ 4,111**	$ 3,815	$ 4,816

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

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2013	$ 5,174	$ (601)	$ 4,573
2014	5,442	(663)	4,779
2015	5,754	(720)	5,034
2016	5,995	(782)	5,213
2017	6,280	(845)	5,435
2018 to 2022	33,822	(4,414)	29,408

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	**2012**	2011
Pension plan assets:			
Domestic equity	26%	**28%**	29%
International equity	25	**24**	25
Fixed income	23	**27**	23
Special situations	3	**1**	—
Real estate investments	14	**13**	14
Private equity	9	**7**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	21%	**22%**	22%
International equity	20	**19**	20
Fixed income	39	**42**	40
Special situations	2	**1**	—
Real estate investments	11	**10**	11
Private equity	7	**6**	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.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2012 and 2011. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

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

The fair values of pension plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 51,433	$ 29,624	$ —	$ 81,057
International equity*	40,337	43,303	—	83,640
Fixed income:				
U.S. Treasury, government, and agency bonds	—	22,820	—	22,820
Mortgage- and asset-backed securities	—	5,618	—	5,618
Corporate bonds	—	38,696	140	38,836
Pooled funds	—	17,656	—	17,656
Cash equivalents and other	209	24,251	—	24,460
Real estate investments	11,410	—	37,196	48,606
Private equity	—	—	26,240	26,240
Total	$ 103,389	$ 181,968	$ 63,576	$ 348,933

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

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

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in thousands)			
Beginning balance	**$ 32,434**	**$ 24,151**	$ 27,976	$ 26,475
Actual return on investments:				
Related to investments held at year end	**4,629**	**44**	2,964	(498)
Related to investments sold during the year	**133**	**3,415**	830	1,951
Total return on investments	**4,762**	**3,459**	3,794	1,453
Purchases, sales, and settlements	—	**(1,370)**	664	(3,777)
Transfers into/out of Level 3	—	—	—	—
Ending balance	**$ 37,196**	**$ 26,240**	$ 32,434	$ 24,151

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 2,561	$ 1,475	$ —	$ 4,036
International equity*	2,008	2,156	—	4,164
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5,187	—	5,187
Mortgage- and asset-backed securities	—	280	—	280
Corporate bonds	—	1,925	7	1,932
Pooled funds	—	879	—	879
Cash equivalents and other	11	1,612	—	1,623
Real estate investments	569	—	1,865	2,434
Private equity	—	14	1,293	1,307
Total	$ 5,149	$ 13,528	$ 3,165	$ 21,842

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

As of December 31, 2011:	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.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012 Real Estate Investments	2012 Private Equity	2011 Real Estate Investments	2011 Private Equity
		(in thousands)		
Beginning balance	**$ 1,851**	**$ 1,377**	$ 1,625	$ 1,538
Actual return on investments:				
Related to investments held at year end	**119**	**(1)**	141	(29)
Related to investments sold during the year	**7**	**90**	47	85
Total return on investments	**126**	**89**	188	56
Purchases, sales, and settlements	**(112)**	**(173)**	38	(217)
Ending balance	**$ 1,865**	**$ 1,293**	$ 1,851	$ 1,377

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2012, 2011, and 2010 were $3.9 million, $3.8 million, and $3.8 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide (CO_2) and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, 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 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. In March 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. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

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

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

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 2010, 2011, and 2012 related to this work were not material. Hundreds of entities have received notices from the TCEQ requesting their participation in the anticipated site remediation. The final impact of this matter on the Company will depend upon further environmental assessment and the ultimate number of potentially responsible parties. The remediation expenses incurred by the Company are expected to be recovered through the Environmental Compliance Overview (ECO) Plan.

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

FERC Matters

In November 2011, the Company filed a request with the FERC for an increase in wholesale base revenues of approximately $32 million under the wholesale cost-based electric tariff. In its filing with the FERC, the Company sought (i) 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) 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) 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 March 9, 2012, the Company entered into a settlement agreement with its wholesale customers with respect to the Company's request for revised rates under the wholesale cost-based electric tariff. The settlement agreement provides that base rates under the cost-based electric tariff will increase by approximately $22.6 million over a 12-month period with revised rates effective April 1, 2012. 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 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 (i) the accounting for Kemper IGCC-related costs that cannot be capitalized, (ii) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (iii) the establishment of a regulatory asset for certain potential plant retirement costs.

On March 28, 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. On September 27, 2012, the Company, with its wholesale customers, filed a final settlement agreement with the FERC. On November 5, 2012, the settlement judge certified the settlement agreement to the FERC with the recommendation that it be approved. The FERC has not yet approved the settlement agreement. 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 the 2004 order establishing the Company's forward-looking PEP, 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 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. In January 2011, the MPUS contested the filing. In June 2011, the Mississippi PSC issued an order approving a joint stipulation between the MPUS and the Company resulting in no change in rates.

In November 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.

In March 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. In May 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. On April 2, 2012, the Company filed a motion to suspend the PEP lookback filing for 2011. Unresolved matters related to certain costs included in the 2010 PEP lookback filing also impact the 2011 PEP lookback filing, making it impractical to determine the Company's actual retail return on investment for 2011 for purposes of the 2011 PEP lookback filing. An order granting the suspension of the 2011 PEP lookback was signed by the Mississippi PSC on May 8, 2012. On or before March 15, 2013, the Company will submit its annual PEP lookback filing for 2012. While the Company does not expect the resolution of these unresolved matters to have a material impact on its financial statements, the ultimate outcome of these matters cannot be determined at this time.

On January 18, 2013, the Company filed its annual PEP filing for 2013, which indicated a rate increase of 1.990%, or $15.8 million, annually.

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

Environmental Compliance Overview Plan

In November 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. In December 2011, an order was issued 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.

On February 14, 2012, the Company submitted its 2012 ECO Plan filing which proposed a 0.3% increase in annual revenues for the Company. In compliance with the certificate of public convenience and necessity (CPCN) to construct a scrubber on Plant Daniel Units 1 and 2, the Company revised the 2012 ECO Plan filing to exclude scrubber expenditures from rate base, which resulted in a 0.16% decrease in annual revenues. On June 22, 2012, the 2012 ECO Plan filing, including the proposed rate decrease, was approved by the Mississippi PSC, effective on June 29, 2012.

On April 3, 2012, the Mississippi PSC approved the Company's request for a CPCN to construct a scrubber on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi (Chancery Court). 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, excluding AFUDC. The project is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the ECO Plan. As of December 31, 2012, total project expenditures were $146.6 million, with the Company's portion being $73.3 million.

On February 12, 2013, the Company submitted its 2013 ECO Plan filing, which proposed no change in rates.

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

Certificated New Plant

See "Integrated Coal Gasification Combined Cycle" for information on certificated new plant and the Company's cost recovery plans.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. On January 18, 2013, in compliance with the Company's filing requirement, the Company requested an annual adjustment of the retail fuel cost recovery factor in an amount equal to a decrease of 4.7% of total 2012 retail revenue. At December 31, 2012, the amount of over recovered retail fuel costs included in the balance sheets was $56.6 million compared to $42.4 million at December 31, 2011. The Company also has a wholesale Municipal and Rural Associations (MRA) and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2013, the wholesale MRA fuel rate decreased resulting in an annual decrease in an amount equal to 3.3% of total 2012 MRA revenue. Effective February 1, 2013, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 5.5% of total 2012 MB revenue. At December 31, 2012, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $19.0 million and $2.1 million compared to $14.3 million and $2.2 million, respectively, at December 31, 2011. In addition, at December 31, 2012, the amount of over recovered MRA emissions allowance cost included in the balance sheets was $0.4 million compared to $1.7 million at December 31, 2011. 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, changes in the billing factor have no significant effect on the Company's revenues or net income, but will affect annual cash flow.

In March 2011, a portion of the Company's territorial wholesale loads that was formerly served under the MB tariff terminated service. Beginning in April 2011, a new power purchase agreement (PPA) went into effect to cover these MB customers as non-territorial load. In June 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 in June 2011.

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. The 2012 audit of fuel-related expenditures began in the second quarter 2012 and was completed in the fourth quarter 2012 with no audit findings.

System Restoration Rider

The Company is required to make annual SRR filings to review charges to the property damage reserve and 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 January 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 May 5, 2011, the filing was approved by the Mississippi PSC. 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 $3.8 million to the property damage reserve in 2012. On April 3, 2012, the filing was approved by the Mississippi PSC. On February 1, 2013, the Company submitted its 2013 SRR rate filing with the Mississippi PSC, which proposed that the 2013 SRR rate level remain at zero and the Company be allowed to accrue $3.2 million to the property damage reserve in 2013. The ultimate outcome of this matter cannot be determined at this time.

Storm Damage Cost Recovery

In August 2012, Hurricane Isaac hit the Gulf Coast of the United States and caused damage within the Company's service area. The estimated total storm restoration costs relating to Hurricane Isaac through December 31, 2012 were $10.5 million. The Company maintains a reserve to cover the cost of damage from major storms to its transmission and distribution facilities and generally the cost of uninsured damage to its generation facilities and other property. At December 31, 2012, the balance in the storm reserve was $58.8 million.

Integrated Coal Gasification Combined Cycle

General

The Company is constructing the Kemper IGCC which will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will use as fuel locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. In connection with the Kemper IGCC, the Company also plans to construct and operate approximately 61 miles of CO_2 pipeline infrastructure. The Kemper IGCC is scheduled to be placed in-service in May 2014.

In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC (2010 MPSC Order). The Sierra Club filed an appeal of the Mississippi PSC's issuance of the CPCN and, on March 15, 2012, the Mississippi Supreme Court reversed the decision of the Chancery Court of Harrison County, Mississippi (Chancery Court) upholding the 2010 MPSC Order and remanded the matter to the Mississippi PSC. The Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN. On March 30, 2012, the Mississippi PSC issued a temporary authorization which allowed the Company to continue construction and, on April 24, 2012, issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC. On April 26, 2012, the Sierra Club appealed the 2012 MPSC Order to the Chancery Court. On December 17, 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court.

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245.3 million of grants awarded to the project by the DOE under the CCPI2 and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and financing costs related to the Kemper IGCC. The 2012 MPSC Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. Exemptions from the cost cap included in the 2012 MPSC Order included the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when the Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on the ratepayers, relative to the original proposal for the CPCN).

The Company's current cost estimate for the Kemper IGCC (net of the $245.3 million CCPI2 grant, and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions as contemplated in the 2012 MPSC Order and the settlement agreement between the Company and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) that must be specifically approved by the Mississippi PSC) is approximately $2.88 billion. The Mississippi PSC and the MPUS have engaged their independent monitors to assess the current cost estimates and schedule projections for the Kemper IGCC. These consultants have issued reports with their own opinions as to the likelihood that costs for the Kemper IGCC will remain at or under the $2.88 billion cost cap and as to the expected in-service date. While the Company continues to believe its cost estimate and schedule projection remain appropriate based on the current status of the project, it is possible that the Company could experience further cost increases and/or schedule delays with respect to the Kemper IGCC. Certain factors have caused and may continue to cause the costs for the Kemper IGCC to increase and/or schedule delays to occur including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials and labor, contractor or supplier delay or non-performance under construction or other agreements, and unforeseen engineering problems. To the extent it becomes probable that costs beyond any permitted exceptions to the cost cap will exceed $2.88 billion or it becomes probable that the Mississippi PSC will disallow a portion of the costs relating to the Kemper IGCC, including certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement, charges to expense may occur and these charges could be material. See "Cost Recovery Plans" below for additional information relating to the Settlement Agreement that defines the process for resolving matters regarding cost recovery related to the Kemper IGCC.

As of December 31, 2012, the Company had spent a total of $2.51 billion on the Kemper IGCC, including the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and other deferred costs. Of this total, $2.47 billion was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $34.9 million was recorded in other regulatory assets, $3.8 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed. 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. 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.

The 2012 MPSC Order established periodic prudence reviews during the annual CWIP review process. Of the total costs of $51 million incurred through March 2009, $46 million has been reviewed and deemed prudent by the Mississippi PSC. Due to the decision of the Mississippi PSC to deny the Certificated New Plant-A (CNP-A) rate filing and a 2012 rate request related to the Kemper IGCC described below, prudence reviews for the construction costs of the Kemper IGCC incurred after March 2009 have not been made. The Settlement Agreement provides for completion of all prudence reviews within six months of the date the Kemper IGCC is placed in service. See "Cost Recovery Plans" herein for additional information.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Cost Recovery Plans

The 2012 MPSC Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. In the 2012 MPSC Order, the Mississippi PSC approved financing cost recovery on CWIP balances not to exceed the $2.4 billion certificated cost estimate for the Kemper IGCC. The 2012 MPSC Order provided for the accrual of AFUDC in 2010 and 2011 and for the current recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of financing cost recovery allowed is to be reduced by the amount of certain state and federal government construction cost incentives received by the Company and must be justified by a showing that such recovery will benefit customers over the life of the Kemper IGCC). With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN.

On June 1, 2012, the MPUS signed a joint stipulation with the Company to establish a proposed rate schedule detailing CNP-A and, on June 14, 2012, the Company submitted to the Mississippi PSC a filing to establish the new CNP-A rate schedule and a stipulated rate increase based upon the revenue request of between $55.3 million and $58.6 million to recover financing costs over the remainder of 2012. On June 22, 2012, the Mississippi PSC denied the proposed CNP-A rate schedule and the 2012 rate recovery filings submitted by the Company, pending a final ruling from the Mississippi Supreme Court regarding the Sierra Club's appeal of the Mississippi PSC's issuance of the CPCN for the Kemper IGCC.

On July 9, 2012, the Company appealed the Mississippi PSC's June 22, 2012 decision to the Mississippi Supreme Court and requested interim rates under bond of $55.3 million. On July 31, 2012, the Mississippi Supreme Court denied the Company's request for interim rates under bond until the Mississippi Supreme Court decides the Company's appeal of the Mississippi PSC's June 22, 2012 decision.

On January 24, 2013, the Company and the Mississippi PSC entered into the Settlement Agreement that (1) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to the Company and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (2) resolves the Company's CNP-A rate appeal before the Mississippi Supreme Court.

On February 12, 2013, the Mississippi Supreme Court granted the Company and the Mississippi PSC's joint filing for dismissal of the Company's appeal of the Mississippi PSC's June 22, 2012 decision.

Under the terms of the Settlement Agreement, the Company and the Mississippi PSC will follow certain agreed-upon regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) the Company's filing within 30 days of the Settlement Agreement of a new request to increase rates in 2013 in an amount not to exceed a $172 million annual revenue requirement, based upon projected investment as of December 31, 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service (which filing for $172 million was made on January 25, 2013); (2) the Mississippi PSC's decision on that matter within 50 days of the Company's request; (3) the Company's collaboration with the MPUS to file with the Mississippi PSC within three months of the Settlement Agreement a rate recovery plan for the Kemper IGCC for the first seven years of its operation, along with a proposed revenue requirement under such plan for 2014 through 2020 (which filing was made on February 26, 2013 as described below); (4) the Mississippi PSC's decision on the rate recovery plan within four months of that filing; (5) the Company's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated cost estimate, plus costs related to the lignite mine and CO_2 pipeline as well as any other costs permitted or determined to be excluded from the cost cap, provided that this limitation will not prevent the Company from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the seven-year rate plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was passed in the Mississippi legislature and was signed by the Governor on February 26, 2013. The Company contemplates using securitization as provided in the legislation as its form of alternate financing for prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement.

On February 26, 2013, the Company, in compliance with the Settlement Agreement, filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The rate recovery plan proposes recovery of an annual revenue requirement of approximately $150 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. Approval of the Company's request to increase rates in 2013 to mitigate the rate impacts of the Kemper IGCC filed on January 25, 2013 is integral to the rate recovery plan as the proposed filing contemplates amortization of the regulatory liability to be used to mitigate rate impacts from 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the rate recovery plan filing, the Company proposes annual recovery to remain the same from 2014 through 2020 and while it is the intent of the Company for the actual revenue requirement to equal the proposed revenue requirement for certain items, the Company proposes that the annual differences for those items through 2020 will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC for determination of the manner of recovery. The Company proposes to secure recovery of prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement to be provided for with alternate financing through securitization. The rate recovery necessary to recover the annual costs of securitization is proposed to be filed and begin after the Kemper IGCC is placed in service.

Under the terms of the Settlement Agreement, the Company has the right to terminate the Settlement Agreement if certain conditions, including the passage of multi-year rate plan legislation that is contemplated under the Settlement Agreement, are not met, if the Company is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Tax Incentives

The Internal Revenue Service (IRS) has allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. The Company's 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 Kemper IGCC during operations in accordance with the rules for Section 48A investment tax credits. Through December 31, 2012, the Company received or accrued tax benefits totaling $361.6 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 bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $170.9 million of these tax credits until after 2013. IRS guidelines allow these unused tax credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then. On October 15, 2012, the Company filed an application with the DOE for certification of the Kemper IGCC for additional tax credits under the Internal Revenue Code Section 48A (Phase III). A portion of the tax credits realized by the Company may be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described below. In addition, all or a portion of the tax credits will be subject to recapture if the Company fails to satisfy the in-service date requirements and carbon capture requirements described above. See Note 5 under "Current and Deferred Income Taxes" for additional information.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014), which is expected to apply to the Kemper IGCC.

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

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site in Kemper County. The mine is scheduled to be placed in-service in June 2013. The estimated capital cost of the mine is approximately $245 million, of which $163.3 million has been incurred through December 31, 2012.

In 2010, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC, a wholly-owned subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operations. Because Liberty Fuels conducts all of its activities on behalf of the Company, Liberty Fuels qualifies as a VIE for which the Company is the primary beneficiary. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all reclamation activities. Consistent with the requirements of consolidation accounting, Liberty Fuels is consolidated in the financial statements of the Company and accordingly the asset retirement cost and the ARO have been recorded in the Company's financial statements. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, the Company will acquire, construct, and operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The estimated capital cost of the CO_2 pipeline facilities is approximately $132 million, of which $78.4 million has been incurred through December 31, 2012.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. On February 28, 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On June 29, 2012, the Company and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012 and reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC, subject to approval by the Mississippi PSC. On December 31, 2012, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013.

The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. On September 27, 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

On March 6, 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, the Company would be required to refund the deposit upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that the Company is assigned a senior unsecured credit rating of BBB+ or lower by Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc. (S&P) or Baa1 or lower by Moody's Investors Services, Inc. (Moody's) or ceases to be rated by either of these rating agencies. Given the interest-bearing nature of the deposit and SMEPA's ability to request a refund, the deposit has been presented as a current liability in the Company's balance sheet herein and as financing proceeds in the Company's statement of cash flows herein.

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

Baseload Act

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. There are legal challenges to the constitutionality of the Baseload Act currently pending before the Mississippi Supreme Court. The ultimate impact of this legislation will depend on the outcome of any legal challenges and cannot be determined at this time. See "Cost Recovery Plans" herein for additional information regarding certain legislation related to the Kemper IGCC.

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, 2012, the Company's percentage ownership and investment in these jointly-owned facilities in commercial operation were as follows:

Generating Plant	Percent Ownership	Plant in Service	Accumulated Depreciation	Construction Work in Progress
		(in thousands)		
Greene County				
Units 1 and 2	40%	$ 89,474	$ 45,402	$ 4,386
Daniel				
Units 1 and 2	50%	$ 293,451	$ 147,833	$ 73,534

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.

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

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 current 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:

	2012	2011	2010
		(in thousands)	
Federal —			
Current	$ 1,212	$ (27,099)	$ 5,399
Deferred	42,929	65,206	35,367
	44,141	38,107	40,766
State —			
Current	1,656	(2,473)	3,319
Deferred	4,594	6,559	2,190
	6,250	4,086	5,509
Total	$ 50,391	$ 42,193	$ 46,275

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

	2012	2011
	(in thousands)	
Deferred tax liabilities —		
Accelerated depreciation	$ 385,899	$ 356,857
Property basis differences	72,451	48,268
Energy cost management clause under recovered	9,492	7,880
Regulatory assets associated with asset retirement obligations	16,851	7,557
Pensions and other benefits	33,756	18,283
Regulatory assets associated with employee benefit obligations	68,717	52,410
Regulatory assets associated with the Kemper IGCC	10,492	4,618
Long-term service agreement	—	5,231
Rate differential	27,270	8,400
Other	33,886	23,802
Total	658,814	533,306
Deferred tax assets —		
Federal effect of state deferred taxes	9,097	10,899
Fuel clause over recovered	38,955	30,050
Other property basis differences	980	2,918
Pension and other benefits	87,416	70,255
Property insurance	23,171	25,349
Premium on long-term debt	26,778	29,820
Unbilled fuel	11,642	14,951
Long-term service agreement	5,544	—
Asset retirement obligations	16,851	7,557
Interest rate hedges	5,644	5,763
Investment tax credit carryforward	170,938	77,400
Other	22,820	21,571
Total	419,836	296,533
Total deferred tax liabilities, net	238,978	236,773
Portion included in (accrued) prepaid income taxes, net	35,815	33,624
Accumulated deferred income taxes	$ 274,793	$ 270,397

At December 31, 2012, the tax-related regulatory assets were $73.0 million. These assets are primarily attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest.

At December 31, 2012, the tax-related regulatory liabilities were $11.2 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits for non-Kemper IGCC related deferred investment tax credits amortized in this manner amounted to $1.2 million, $1.3 million, and $1.3 million for 2012, 2011, and 2010, respectively. At December 31, 2012, all non-Kemper IGCC 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, 2012, the Company had $361.6 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 2012 and 2013, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $170.9 million of these tax credits until after 2013. 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 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 include100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013).

Effective Tax Rate

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

	2012	2011	2010
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.0**	1.9	2.8
Non-deductible book depreciation	**0.2**	0.3	0.3
Medicare subsidy	**(0.1)**	(0.1)	(0.2)
AFUDC-equity	**(11.3)**	(6.3)	(1.0)
Other	**(0.7)**	(0.2)	(0.8)
Effective income tax rate	**25.1%**	30.6%	36.1%

The Company's 2012 effective tax rate decreased from 2011 primarily due to the increase in non-taxable AFUDC equity related to increased construction expenditures.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits increased by $0.8 million, resulting in a balance of $5.8 million as of December 31, 2012.

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

	2012	2011	2010
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 4,964**	$ 4,288	$ 3,026
Tax positions from current periods	**1,186**	1,486	868
Tax positions from prior periods	**(26)**	(810)	611
Reductions due to expired statute of limitations	**—**	—	(217)
Settlements with taxing authorities	**(369)**	—	—
Balance at end of year	**$ 5,755**	$ 4,964	$ 4,288

The change in tax positions from current periods for 2012 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 2012 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:

		2012		2011		2010
				(in thousands)		
Tax positions impacting the effective tax rate	**$**	**3,656**	$	4,144	$	3,058
Tax positions not impacting the effective tax rate		**2,099**		820		1,230
Balance of unrecognized tax benefits	**$**	**5,755**	$	4,964	$	4,288

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

Accrued interest for unrecognized tax benefits was as follows:

		2012		2011		2010
				(in thousands)		
Interest accrued at beginning of year	**$**	**680**	$	413	$	230
Interest accrued during the year		**92**		267		183
Balance at end of year	**$**	**772**	$	680	$	413

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

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. The IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

6. FINANCING

Bank Term Loans

In March 2012, the Company paid at maturity a $75 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month London Interbank Offered Rate (LIBOR).

In September 2012, the Company paid at maturity a $40 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month LIBOR.

In November 2012, the Company entered into a 366-day $100 million aggregate principal amount floating rate bank loan that bears interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used solely for working capital and for other general corporate purposes, including the Company's continuous construction program.

At December 31, 2012 and 2011, the Company had $175 million and $240 million of bank loans outstanding, respectively.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and other hybrid securities. At December 31, 2012, the Company was in compliance with its debt limits.

In addition, these bank loans contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness above a specified threshold. The cross default provisions are restricted to the indebtedness, including any guarantee obligations, of the company that has such bank loans. The Company is currently in compliance with all such covenants.

Senior Notes

In March 2012, the Company issued $250.0 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042 and an additional $150.0 million aggregate principal amount of Series 2011A 2.35% Senior Notes due October 15, 2016. The Series 2011A Senior Notes were of the same series of notes that were originally issued in October 2011 in the aggregate principal amount of $150.0 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2011A Senior Notes was $300.0 million. The proceeds from the sales of the Series 2012A Senior Notes and the Series 2011A Senior Notes were used to repay a bank term loan in an aggregate principal amount of $75.0 million and for general corporate purposes, including the Company's continuous construction program.

In March 2012, $300.0 million in interest rate swaps were settled, of which $250.0 million related to the Series 2012A Senior Notes at a loss of approximately $13.3 million, which will be amortized to interest expense, in earnings, over 10 years, and $50.0 million related to the Series 2011A Senior Notes at a loss of approximately $2.7 million, which will be amortized to interest expense, in earnings, over 10 years.

In May 2012, the Company redeemed $90.0 million aggregate principal amount of Series E 5-5/8% Senior Notes due May 1, 2033.

In August 2012, the Company issued an additional $200.0 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042. The Series 2012A Senior Notes were of the same series of notes that were originally issued in March 2012 in the aggregate principal amount of $250.0 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2012A Senior Notes is $450.0 million. The proceeds from this sale of the Series 2012A Senior Notes were used for general corporate purposes, including the Company's continuous construction program.

At December 31, 2012 and 2011, the Company had $1.1 billion and $630.0 million of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company. See "Plant Daniel Revenue Bonds" below for additional information regarding the Company's secured indebtedness.

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 $270.0 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, 2012 and 2011 was as follows:

	2012	2011
	(in millions)	
Senior notes	$ **50.0**	$ —
Bank term loans	**175.0**	240.0
Revenue bonds	**51.5**	—
Capitalized leases	—	0.6
Outstanding at December 31	$ **276.5**	$ 240.6

Maturities through 2017 applicable to total long-term debt are as follows: $276.5 million in 2013, $300.0 million in 2016, and $35.0 million in 2017. 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 and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2012 and 2011 was $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 issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.

In August 2012, the Mississippi Business Finance Corporation (MBFC) entered into an agreement to issue up to $42.5 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012A (Mississippi Power Company Project), up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012B (Mississippi Power Company Project), and up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012C (Mississippi Power Company Project) for the benefit of the Company. During 2012, the MBFC issued $8.97 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A, $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012B, and $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012C for the benefit of the Company. The proceeds were used to reimburse the Company for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. Any future issuances of the Series 2012A bonds will be used for this same purpose.

The Company had $50.0 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2012 and 2011, and $51.5 million of such obligations related to taxable revenue bonds outstanding at December 31, 2012. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Other Obligations

In March 2012, the Company received a $150.0 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at the Company's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that the Company is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies.

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" and "Plant Daniel Revenue Bonds" for additional information. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy the obligations of Southern Company or another of its other subsidiaries.

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. The preferred stock and depositary preferred stock is subject to redemption at the option of the Company 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, 2012, committed credit arrangements with banks were as follows:

Expires[a]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
		(in millions)					
$135	$165	$300	$300	$25	$40	$65	$70

(a) No credit arrangements expire after 2014.

The Company expects to renew its credit arrangements, as needed, prior to expiration.

Most of these credit arrangements require payment of 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.

Most of these credit arrangements contain covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities.

In addition, the credit arrangements typically contain cross default provisions that are restricted to the indebtedness of the Company. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowing.

The Company's unused credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2012 was $40.1 million.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements.

At December 31, 2012 and 2011, there was no short-term debt outstanding.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $411.2 million, $490.4 million, and $501.8 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

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 was $11.1 million, $32.6 million, and $38.6 million for 2012, 2011, and 2010 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 aluminum railcars for the transportation of coal at Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value, or to renew the leases at the end of 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 229 aluminum railcars. The Company and Gulf Power also have separate lease agreements for other railcars that do not contain a purchase option.

The Company's share (50%) of the leases, charged to fuel stock and recovered through the fuel cost recovery clause, was $3.6 million in 2012, $2.6 million in 2011, and $3.5 million in 2010. The Company's annual railcar lease payments for 2013 through 2017 will average approximately $1.6 million.

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 $0.2 million in 2012, $0.4 million in 2011, and $0.7 million in 2010. The Company's annual lease payments for 2013 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 $7.3 million in 2012, $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 2013 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, 2012, there were 241 current and former employees of the Company participating in the stock option program and there were 39 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

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

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

Year Ended December 31	2012	2011	2010
Expected volatility	**17.7%**	17.5%	17.4%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**0.9%**	2.3%	2.4%
Dividend yield	**4.2%**	4.8%	5.6%
Weighted average grant-date fair value	**$3.39**	$3.23	$2.23

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

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	1,569,728	$ 33.59
Granted	278,709	44.46
Exercised	(474,871)	31.98
Cancelled	—	—
Outstanding at December 31, 2012	**1,373,566**	**$ 36.34**
Exercisable at December 31, 2012	**864,634**	**$ 33.96**

The number of stock options vested, and expected to vest in the future, as of December 31, 2012 was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $9.3 million and $7.7 million, respectively.

As of December 31, 2012, there was $0.3 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $0.9 million, $0.8 million, and $0.8 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.3 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011, and 2010 was $4.9 million, $4.2 million, and $2.7 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.9 million, $1.6 million, and $1.0 million for the years ended December 31, 2012, 2011, and 2010, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return

(TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

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

Total unvested performance share units outstanding as of December 31, 2011 were 70,830. During 2012, 33,077 performance share units were granted, 32,208 performance share units were vested, and 3,213 performance share units were forfeited resulting in 68,486 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 43,481 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $1.2 million, $0.7 million, and $0.3 million, respectively, with the related tax benefit also recognized in income of $0.4 million, $0.3 million, and $0.1 million, respectively. As of December 31, 2012, there was $1.4 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

9. FAIR VALUE MEASUREMENTS

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

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

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

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Energy-related derivatives	$ —	$ 2,519	$ —	$ 2,519
Foreign currency derivatives	—	—	—	—
Cash equivalents	125,600	—	—	125,600
Total	$ 125,600	$ 2,519	$ —	$ 128,119
Liabilities:				
Energy-related derivatives	$ —	$ 19,446	$ —	$ 19,446
Interest rate derivatives	—	—	—	—
Foreign currency derivatives	—	37	—	37
Total	$ —	$ 19,483	$ —	$ 19,483

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

	Fair Value Measurements Using			
As of December 31, 2011:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Energy-related derivatives	$ —	$ 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

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, 2012 and 2011, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2012	*(in thousands)*			
Cash equivalents:				
Money market funds	$ 125,600	None	Daily	Not applicable
As of December 31, 2011				
Cash equivalents:				
Money market funds	$ 133,900	None	Daily	Not applicable

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

As of December 31, 2012 and 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2012	**$ 1,840,933**	**$ 1,956,799**
2011	$ 1,343,596	$ 1,426,808

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

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk 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 and are presented on a gross basis.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel hedging programs, implemented per the guidelines of the 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, 2012, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

	Gas	
Net Purchased mmBtu*	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in millions)		
38	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, 2013 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. During the year ended December 31, 2011, certain fair value hedges were de-designated and subsequently settled in 2012. The ineffectiveness related to the de-designated hedges was recorded as a regulatory asset and was immaterial to the Company. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2012, the following foreign currency derivatives were outstanding:

	Notional Amount	Forward Rate	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2012
	(in thousands)			*(in thousands)*
Fair value hedges of firm commitments				
	EUR735	1.3758 Dollars per Euro	March 2014	$(37)

Interest Rate Derivatives

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

At December 31, 2012, there were no interest rate derivatives outstanding.

For the year ended December 31, 2012, the Company had realized net losses of $16.0 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these losses 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 12-month period ending December 31, 2013 are $1.4 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, 2012 and 2011, 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**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 638**	$ 125	Liabilities from risk management activities	**$ 13,116**	$ 36,455
	Other deferred charges and assets	**1,881**	37	Other deferred credits and liabilities	**6,330**	14,697
Total derivatives designated as hedging instruments for regulatory purposes		**$ 2,519**	$ 162		**$ 19,446**	$ 51,152
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	**$ —**	$ —	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	Liabilities from risk management activities	**—**	625
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**37**	46
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ —**	$ 19		**$ 37**	$ 15,879
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ —**	$ —	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		**$ —**	$ 1,839
Total		**$ 2,519**	$ 1,688		**$ 19,483**	$ 68,870

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

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

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (13,116)**	$ (36,455)	Other regulatory liabilities, current	**$ 638**	$ 125
	Other regulatory assets, deferred	**(6,330)**	(14,697)	Other regulatory liabilities, deferred	**1,881**	37
Total energy-related derivative gains (losses)		**$ (19,446)**	$ (51,152)		**$ 2,519**	$ 162

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	**2012**	2011	2010	**Statements of Income Location**	**2012**	2011	2010
		(in thousands)				*(in thousands)*	
Energy-related derivatives	**$ —**	$ (3)	$ 3	Fuel	**$ —**	$ —	$ —
Interest rate derivatives	**(774)**	(14,361)	—	Interest Expense	**(1,073)**	48	—
Total	**$ (774)**	$ (14,364)	$ 3		**$ (1,073)**	$ 48	$ —

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

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were immaterial. For the year ended December 31, 2012, 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 years ended December 31, 2012 and 2011, the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments, which include a pre-tax loss associated with de-designated hedges prior to de-designation, on the Company's statements of income were a $0.6 million gain and $3.6 million loss, respectively. For the year ended December 31, 2010, the pre-tax gain was $3.3 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, 2012, the fair value of derivative liabilities with contingent features was $2.9 million.

At December 31, 2012, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $15.1 million.

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

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in thousands)	
March 2012	**$ 228,714**	**$ 30,213**	**$ 25,255**
June 2012	**266,084**	**46,986**	**35,027**
September 2012	**305,419**	**66,151**	**54,625**
December 2012	**235,779**	**31,662**	**33,200**
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

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

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

	2012	2011	2010	2009	2008
Operating Revenues (in thousands)	**$ 1,035,996**	$ 1,112,877	$ 1,143,068	$ 1,149,421	$ 1,256,542
Net Income After Dividends on Preferred Stock (in thousands)	**$ 148,107**	$ 94,182	$ 80,217	$ 84,967	$ 85,960
Cash Dividends on Common Stock (in thousands)	**$ 106,800**	$ 75,500	$ 68,600	$ 68,500	$ 68,400
Return on Average Common Equity (percent)	**10.41**	10.54	11.49	13.12	13.75
Total Assets (in thousands)	**$ 5,451,621**	$ 3,671,842	$ 2,476,321	$ 2,072,681	$ 1,952,695
Gross Property Additions (in thousands)	**$ 1,665,498**	$ 1,205,704	$ 340,162	$ 95,573	$ 139,250
Capitalization (in thousands):					
Common stock equity	**$ 1,797,373**	$ 1,049,217	$ 737,368	$ 658,522	$ 636,451
Redeemable preferred stock	**32,780**	32,780	32,780	32,780	32,780
Long-term debt	**1,564,462**	1,103,596	462,032	493,480	370,460
Total (excluding amounts due within one year)	**$ 3,394,615**	$ 2,185,593	$ 1,232,180	$ 1,184,782	$ 1,039,691
Capitalization Ratios (percent):					
Common stock equity	**52.9**	48.0	59.8	55.6	61.2
Redeemable preferred stock	**1.0**	1.5	2.7	2.8	3.2
Long-term debt	**46.1**	50.5	37.5	41.6	35.6
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**152,265**	151,805	151,944	151,375	152,280
Commercial	**33,112**	33,200	33,121	33,147	33,589
Industrial	**472**	496	504	513	518
Other	**175**	175	187	180	183
Total	**186,024**	185,676	185,756	185,215	186,570
Employees (year-end)	**1,281**	1,264	1,280	1,285	1,317

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

	2012	2011	2010	2009	2008
Operating Revenues (in thousands):					
Residential	**$ 226,847**	$ 246,510	$ 256,994	$ 245,357	$ 248,693
Commercial	**250,860**	263,256	266,406	269,423	271,452
Industrial	**262,978**	275,752	267,588	269,128	258,328
Other	**6,768**	6,945	6,924	7,041	6,961
Total retail	**747,453**	792,463	797,912	790,949	785,434
Wholesale — non-affiliates	**255,557**	273,178	287,917	299,268	353,793
Wholesale — affiliates	**16,403**	30,417	41,614	44,546	100,928
Total revenues from sales of electricity	**1,019,413**	1,096,058	1,127,443	1,134,763	1,240,155
Other revenues	**16,583**	16,819	15,625	14,658	16,387
Total	**$ 1,035,996**	$ 1,112,877	$ 1,143,068	$ 1,149,421	$ 1,256,542
Kilowatt-Hour Sales (in thousands):					
Residential	**2,045,999**	2,162,419	2,296,157	2,091,825	2,121,389
Commercial	**2,915,934**	2,870,714	2,921,942	2,851,248	2,856,744
Industrial	**4,701,681**	4,586,356	4,466,560	4,329,924	4,187,101
Other	**38,588**	38,684	38,570	38,855	38,886
Total retail	**9,702,202**	9,658,173	9,723,229	9,311,852	9,204,120
Wholesale — non-affiliates	**3,818,773**	4,009,637	4,284,289	4,651,606	5,016,655
Wholesale — affiliates	**571,908**	648,772	774,375	839,372	1,487,083
Total	**14,092,883**	14,316,582	14,781,893	14,802,830	15,707,858
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.09**	11.40	11.19	11.73	11.72
Commercial	**8.60**	9.17	9.12	9.45	9.50
Industrial	**5.59**	6.01	5.99	6.22	6.17
Total retail	**7.70**	8.21	8.21	8.49	8.53
Wholesale	**6.19**	6.52	6.51	6.26	6.99
Total sales	**7.23**	7.66	7.63	7.67	7.90
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,426**	14,229	15,130	13,762	13,992
Residential Average Annual Revenue Per Customer	**$ 1,489**	$ 1,622	$ 1,693	$ 1,614	$ 1,640
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**3,088**	3,156	3,156	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,168**	2,618	2,792	2,392	2,385
Summer	**2,435**	2,462	2,638	2,522	2,458
Annual Load Factor (percent)	**61.9**	59.1	57.9	60.7	61.5
Plant Availability Fossil-Steam (percent)*	**91.5**	87.7	93.8	94.1	91.6
Source of Energy Supply (percent):					
Coal	**22.8**	34.9	43.0	40.0	58.7
Oil and gas	**63.9**	51.5	41.9	43.6	28.6
Purchased power -					
From non-affiliates	**2.0**	1.4	1.3	3.3	4.4
From affiliates	**11.3**	12.2	13.8	13.1	8.3
Total	**100.0**	100.0	100.0	100.0	100.0

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

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
(Resigned effective 6/30/2012)
President
University of Southern Mississippi
Hattisburg, Mississippi

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
Corporate Services and Community Relations

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

Jeff G. Franklin
Vice President
Customer Services Organization

R. Allen Reaves
Vice President and Senior Production Officer

Billy F. Thornton
Vice President
Legislative and Regulatory Affairs
(Elected effective 10/22/2012)

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

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 2012, retail energy sales accounted for 68.8% of the Company's total sales of 14.1 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, LLC
P.O. Box 43006
Providence, RI 02940-3006
(800) 554-7626

www.computershare.com/investor

Trustee, Registrar, and Interest Paying Agent

All series of Senior Notes
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	2012	2011
	(in thousands)	
First	$26,700	$18,875
Second	26,700	18,875
Third	26,700	18,875
Fourth	26,700	18,875

Number of Preferred Shareholders of record as of December 31, 2012 was 213.

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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