MISSISSIPPI POWER COMPANY

2013 ANNUAL REPORT

MISSISSIPPI POWER

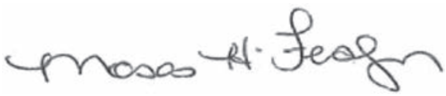
A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2013 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 (1992)* 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, 2013.

President and Chief Executive Officer



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

February 27, 2014

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, 2013 and 2012, 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, 2013. 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 83) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Mississippi Power Company 2013 Annual Report

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 Company's 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 prudently-incurred 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 and related to the successful completion of ongoing construction projects, primarily the new integrated coal gasification combined cycle electric generating plant located in Kemper County, Mississippi (Kemper IGCC). 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 the Kemper IGCC, which is scheduled to be placed into service in the fourth quarter 2014. The certificated cost estimate of the Kemper IGCC established by the Mississippi PSC was $2.4 billion with a construction cost cap of $2.88 billion, net of $245.3 million of grants awarded to the project by the U.S. Department of Energy (DOE) under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the carbon dioxide (CO_2) pipeline facilities, allowance for funds used during construction (AFUDC), 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 customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The Company’s current cost estimate for the Kemper IGCC in total is approximately $5.04 billion, which includes approximately $4.06 billion of costs subject to the construction cost cap. The Company does not intend to seek any rate recovery or joint owner contributions for any related costs that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. As a result, the Company recorded pre-tax charges to income for revisions to the cost estimate of $78.0 million ($48.2 million after tax) and $1.10 billion ($680.5 million after tax) in 2012 and 2013, respectively.

On January 24, 2013, the Company entered into a settlement agreement (Settlement Agreement) with the Mississippi PSC that, among other things, establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC. Consistent with the terms of the Settlement Agreement, on March 5, 2013, the Mississippi PSC issued an order (2013 MPSC Rate Order) approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. Amounts collected through these rates are being recorded as a regulatory liability to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service. Also consistent with the Settlement Agreement, the Company has filed with the Mississippi PSC 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 (Seven-Year Rate Plan). The Seven-Year Rate Plan would include recovery of prudently-incurred Kemper IGCC costs up to the $2.4 billion certificated cost estimate, plus certain exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the construction cost cap by the Mississippi PSC.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was enacted into law on February 26, 2013. The Company intends to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs as approved by the Mississippi PSC. The Company expects to request recovery of the annual costs of securitization after the Kemper IGCC is placed in service and following completion of the Mississippi PSC's final prudence review of costs for the Kemper IGCC. The Mississippi PSC's prudence review of Kemper IGCC costs incurred through March 31, 2013, as provided for in the Settlement Agreement, is expected to occur in the second quarter 2014. A final review of all costs incurred after March 31, 2013 is expected to be completed within six months of the Kemper IGCC’s in-service date. See

Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information, including the discussion of risks related to the Kemper IGCC.

Key Performance Indicators

The Company continues to focus on several key performance indicators, including the construction of the Kemper IGCC. 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 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 2013 fossil Peak Season EFOR was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The 2013 performance was better than the target for these reliability measures.

Net income (loss) after dividends on preferred stock is the primary measure of the Company's financial performance. The Company was below target for 2013 net income after dividends on preferred stock primarily due to revisions to the cost estimate for the Kemper IGCC that exceeded the $2.88 billion cost cap and lower retail and wholesale base revenue, partially offset by lower operations and maintenance expenses and higher 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 – "Integrated Coal Gasification Combined Cycle" herein for additional information.

The Company's 2013 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2013 Target Performance	2013 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season EFOR	**5.86% or less**	**0.84%**
Net income (loss) after dividends on preferred stock	**$206.8 million**	**$(476.6) million**
Estimated loss on Kemper IGCC		**$680.5 million**
Net income (loss), excluding estimated loss on Kemper IGCC*		**$203.9 million**

*Does not reflect income (loss) as calculated in accordance with generally accepted accounting principles (GAAP). The Company's management uses the non-GAAP measure of income (loss) to evaluate the performance of the Company's ongoing business activities. The Company's management believes the presentation of this non-GAAP measure of income (loss) is useful for investors because it provides earnings information that is consistent with the historical and ongoing business activities of the Company. The presentation of this information is not meant to be considered a substitute for financial measures prepared in accordance with GAAP.

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's net income (loss) after dividends on preferred stock was ($476.6) million in 2013 compared to $99.9 million in 2012. The decrease in 2013 was primarily the result of $1.1 billion in pre-tax charges ($680.5 million after-tax) for revisions of estimated costs expected to be incurred on the Company’s construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions. These charges were partially offset by an increase in AFUDC equity primarily related to the construction of the Kemper IGCC which began in 2010 and an increase in revenues primarily due to retail and wholesale base rate increases and a retail rate increase related to the Kemper IGCC cost recovery that became effective in April 2013. 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 (loss) after dividends on preferred stock was $99.9 million in 2012 compared to $94.2 million in 2011. The 6.1% increase in 2012 was primarily the result of an increase in AFUDC equity related to the construction of the Kemper IGCC, 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 largely offset by a $78.0 million pre-tax charge ($48.2 million after-tax) for a revision of estimated costs expected to be incurred on the Company's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions.

RESULTS OF OPERATIONS

A condensed statement of operations follows:

	Amount	Increase (Decrease) from Prior Year	
	2013	**2013**	2012
		(in millions)	
Operating revenues	**$ 1,145.2**	**$ 109.2**	$ (76.9)
Fuel	**491.3**	**80.0**	(79.2)
Purchased power	**48.3**	**(6.8)**	(16.7)
Other operations and maintenance	**253.3**	**24.7**	(37.7)
Depreciation and amortization	**91.4**	**4.9**	6.2
Taxes other than income taxes	**80.7**	**1.2**	9.3
Estimated loss on Kemper IGCC	**1,102.0**	**1,024.0**	78.0
Total operating expenses	**2,067.0**	**1,128.0**	(40.1)
Operating income	**(921.8)**	**(1,018.8)**	(36.8)
Allowance for equity funds used during construction	**121.6**	**56.8**	40.1
Interest income	**0.2**	**(0.6)**	(0.6)
Interest expense, net of amounts capitalized	**36.5**	**(4.4)**	19.1
Other income (expense), net	**(6.2)**	**(6.7)**	0.5
Income taxes (benefit)	**(367.8)**	**(388.4)**	(21.6)
Net income (loss)	**(474.9)**	**(576.5)**	5.7
Dividends on preferred stock	**1.7**	**—**	—
Net income (loss) after dividends on preferred stock	**$ (476.6)**	**$ (576.5)**	$ 5.7

Operating Revenues

Operating revenues for 2013 were $1.1 billion, reflecting a $109.2 million increase from 2012. Details of operating revenues were as follows:

	Amount	
	2013	2012
	(in millions)	
Retail — prior year	**$ 747.5**	$ 792.5
Estimated change resulting from —		
Rates and pricing	**18.2**	(2.0)
Sales growth (decline)	**(0.7)**	9.0
Weather	**1.2**	(9.8)
Fuel and other cost recovery	**32.9**	(42.2)
Retail — current year	**799.1**	747.5
Wholesale revenues —		
Non-affiliates	**293.9**	255.5
Affiliates	**34.8**	16.4
Total wholesale revenues	**328.7**	271.9
Other operating revenues	**17.4**	16.6
Total operating revenues	**$ 1,145.2**	$ 1,036.0
Percent change	**10.5%**	(6.9)%

Total retail revenues for 2013 increased 6.9% compared to 2012 primarily as a result of a base rate increase, a rate increase related to Kemper IGCC cost recovery that became effective in April 2013, and higher fuel cost recovery revenues in 2013 compared to 2012. 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. 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. Fuel and other cost recovery revenues increased in 2013 compared to 2012 primarily as a result of higher recoverable fuel costs, partially offset by a decrease in revenues related to ad valorem taxes.

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. 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's 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. The Company serves long-term contracts with rural electric cooperatives association 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 22.2% of the Company's total operating revenues in 2013 and are largely subject to rolling 10-year cancellation notices.

Wholesale revenues from sales to non-affiliates increased $38.4 million, or 15.0%, in 2013 compared to 2012 as a result of a $20.5 million increase in base revenues primarily resulting from a wholesale base rate increase effective April 1, 2013 and a $17.8 million increase in energy revenues, of which $14.0 million was associated with higher fuel prices and $3.8 million was associated with an increase in kilowatt-hour (KWH) sales. 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 KWH sales, partially offset by a wholesale base rate increase effective April 1, 2012.

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 affiliates will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales 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 affiliates increased $18.4 million in 2013 compared to 2012 due to a $1.3 million increase in capacity revenues and a $17.1 million increase in energy revenues of which $7.2 million was associated with higher prices and $9.9 million was associated with an increase in KWH sales. Wholesale revenues from sales to affiliates decreased $14.0 million 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.

Other operating revenues in 2013 increased $0.8 million, or 4.8%, from 2012 primarily due to a $0.5 million increase in transmission revenues and a $0.3 million increase in miscellaneous revenue from timber and easement sale proceeds. 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.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2013 and percent change by year were as follows:

	Total KWHs	**Total KWH Percent Change**		**Weather-Adjusted Percent Change**	
	2013	**2013**	2012	**2013**	2012
	(in millions)				
Residential	**2,088**	**2.0%**	(5.4)%	**—%**	2.3%
Commercial	**2,865**	**(1.7)**	1.6	**(1.1)**	1.7
Industrial	**4,739**	**0.8**	2.5	**0.8**	2.5
Other	**40**	**4.0**	(0.2)	**4.0**	(0.2)
Total retail	**9,732**	**0.3**	0.5	**0.1%**	2.2%
Wholesale					
Non-affiliated	**3,929**	**2.9**	(4.8)		
Affiliated	**931**	**62.8**	(11.8)		
Total wholesale	**4,860**	**10.7**	(5.7)		
Total energy sales	**14,592**	**3.5%**	(1.6)%		

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

Residential energy sales increased 2.0% in 2013 compared to 2012 due to less mild weather and a slight increase in the number of residential customers in 2013 compared to 2012. Residential energy sales decreased 5.4% in 2012 compared to 2011 due to milder than normal weather, partially offset by a slight increase in the number of residential customers in 2012 compared to 2011.

Commercial energy sales decreased 1.7% in 2013 compared to 2012 due to decreased economic activity in 2013 compared to 2012. Commercial energy sales increased 1.6% in 2012 compared to 2011 due to increased economic activity in 2012 compared to 2011.

Industrial energy sales increased 0.8% in 2013 compared to 2012 due to increased usage by larger industrial customers as well as expansions of some existing customers. 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.

Wholesale energy sales to non-affiliates increased 2.9% in 2013 compared to 2012 primarily due to increased KWH sales to rural electric cooperative associations and municipalities located in southeastern Mississippi resulting from less mild weather in 2013 compared to 2012. 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.

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 increased 62.8% in 2013 compared to 2012 primarily due to an increase in the Company's generation, resulting in more energy available to sell to affiliate companies. Wholesale energy sales to affiliates decreased 11.8% in 2012 compared to 2011 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:

	2013	2012	2011
Total generation *(millions of KWHs)*	**13,721**	12,750	12,986
Total purchased power *(millions of KWHs)*	**1,559**	1,961	2,055
Sources of generation *(percent)* –			
Coal	**36**	26	40
Gas	**64**	74	60
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**4.97**	5.09	4.39
Gas	**3.16**	2.90	3.88
Average cost of fuel, generated *(cents per net KWH)*	**3.87**	3.53	4.10
Average cost of purchased power *(cents per net KWH)*	**3.10**	2.81	3.49

Fuel and purchased power expenses were $539.6 million in 2013, an increase of $73.2 million, or 15.7%, above the prior year costs. The increase was primarily due to a $55.1 million increase in the total volume of KWHs generated and purchased and an $18.1 million increase in the cost of fuel and purchased power. 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 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 increased $80.0 million, or 19.5%, in 2013 compared to 2012. The increase was the result of a 9.6% increase in the average cost of fuel per KWH generated and a 9.0% increase in the volume of KWHs generated resulting from increased non-territorial sales in 2013 compared to 2012. Fuel expense decreased $79.2 million, or 16.1%, in 2012 compared to 2011. The decrease was the result of a 13.9% decrease in the average cost of fuel per KWH generated and a 2.6% decrease in the volume of KWHs generated resulting from decreased non-territorial sales in 2012 as compared to 2011.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates increased $0.5 million, or 10.2%, in 2013 compared to 2012. The increase was the result of an 8.0% increase in the average cost per KWH purchased and a 2.0% increase in the volume of KWHs purchased. The increase in the average cost per KWH purchased was due to a higher 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 $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 per KWH purchased, partially offset by a 42.3% increase in the 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.

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 $7.3 million, or 14.7%, in 2013 compared to 2012. The decrease was primarily the result of a 24.7% decrease in the volume of KWHs purchased, partially offset by a 13.2% increase in the average cost per KWH purchased. 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 per KWH purchased and a 10.0% decrease in the volume of KWHs purchased.

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 increased $24.7 million in 2013 compared to 2012 primarily due to a $9.8 million increase in generation maintenance expenses for several planned outages, a $7.6 million increase in administrative and general expenses, a $4.2 million increase in transmission maintenance expenses, a $2.8 million increase in customer accounting primarily due to uncollectibles, and a $2.5 million increase in distribution expenses related to overhead line maintenance and vegetation management costs. These increases were partially offset by a $2.7 million decrease in labor 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.

Depreciation and Amortization

Depreciation and amortization increased $4.9 million in 2013 compared to 2012 primarily due to a $4.3 million increase in Environmental Compliance Overview (ECO) Plan amortization, a $2.0 million increase in amortization resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4, and a $1.6 million increase in depreciation resulting from an increase in plant in service. These increases were partially offset by a $2.1 million decrease in amortization primarily resulting from a regulatory deferral associated with the Kemper IGCC and a $0.7 million decrease in amortization resulting from a regulatory deferral associated with the capital lease related to the Kemper IGCC air separation unit.

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 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.

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 $1.2 million in 2013 compared to 2012 primarily as a result of a $3.5 million increase in franchise taxes, partially offset by a $2.1 million decrease in ad valorem taxes and a $0.2 million decrease in payroll 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.

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.

Estimated Loss on Kemper IGCC

Estimated probable losses on the Kemper IGCC of $1.1 billion and $78.0 million were recorded in 2013 and 2012, respectively, to reflect revisions of estimated costs expected to be incurred on the construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Allowance for Funds Used During Construction Equity

AFUDC equity increased $56.8 million in 2013 as compared to 2012 and $40.1 million in 2012 as compared to 2011. These increases were primarily due 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 decreased $4.4 million in 2013 compared to 2012, primarily due to a $20.1 million increase in capitalized interest primarily resulting from AFUDC debt associated with the Kemper IGCC and a $2.6 million decrease in interest expense associated with the redemption of long-term debt in 2013. These decreases were partially offset by a $12.2 million increase in interest expense primarily associated with the issuances of new long-term debt in 2013, a $4.0 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, and a $2.7 million increase in interest expense on the regulatory liability related to the Kemper IGCC rate recovery.

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 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. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Other Income (Expense), Net

Other income (expense), net decreased $6.7 million in 2013 compared to 2012 primarily due to a $5.9 million increase in consulting fees. 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 consulting fees.

Income Taxes

Income taxes decreased $388.4 million in 2013 compared to 2012 primarily resulting from the reduction in pre-tax earnings related to the estimated probable losses on the Kemper IGCC. Income taxes decreased $21.6 million in 2012 compared to 2011 primarily resulting from lower pre-tax earnings as a result of the estimated probable loss on the Kemper IGCC, an increase in AFUDC equity, which is non-taxable, and a decrease in unrecognized tax benefits, partially offset by lower State of Mississippi manufacturing investment tax credits.

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, primarily the Kemper IGCC. 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 other 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 regional and global economic conditions impact sales for the Company, as 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

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the U.S. Environmental Protection Agency (EPA) brought civil enforcement actions in federal district court against Alabama Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies 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 Alabama Power (including claims involving a unit co-owned by the Company) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for Alabama Power on all remaining claims and dismissal of the case with prejudice in 2011. On September 19, 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of Alabama Power, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

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.

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 2013, the Company had invested approximately $405 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $104 million, $52 million, and $23 million for 2013, 2012, and 2011, respectively. The Company expects that base level capital expenditures to comply with environmental statutes and regulations will total approximately $313 million from 2014 through 2016, with annual totals of approximately $154 million, $108 million, and $51 million for 2014, 2015, and 2016, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion residuals rules and to evaluate compliance options. Based on its preliminary analysis and an assumption that coal combustion residuals will continue to be regulated as non-hazardous solid waste under the proposed rule, the Company does not anticipate that material compliance costs with respect to these proposed rules will be required during the period of 2014 through 2016. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2016, 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 Residuals" 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 residuals, 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 $278 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), which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA may designate additional areas as nonattainment in the future, which could include areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On February 13, 2014, the EPA proposed to delete from the Alabama State Implementation Plan (SIP) the Alabama opacity rule that the EPA approved in 2008, which provides operational flexibility to affected units. On March 6, 2013, the U.S. Court of Appeals for the Eleventh Circuit ruled in favor of Alabama Power and vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA’s latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act. Alabama Power believes this interpretation of the Clean Air Act to be incorrect. If finalized, this proposed action could affect unit availability and result in increased operations and maintenance costs for affected units, including units co-owned by the Company.

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 2011, the EPA promulgated the Cross State Air Pollution Rule (CSAPR) to replace CAIR. However, in August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. Review of the U.S. Court of Appeals for the District of Columbia Circuit's decision regarding CSAPR is currently pending before the U.S. Supreme Court.

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 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 February 2012, the EPA finalized the Mercury and Air Toxics Standards (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; however, states may authorize a compliance extension of up to one year to April 16, 2016. The Company has received this one-year compliance extension for Plant Daniel.

In August 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 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. The EPA has entered into a settlement agreement requiring it to finalize the rule by June 12, 2014.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. The impacts of the SO_2 NAAQS, the Alabama opacity rule, 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 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 is required to issue a final rule by April 17, 2014.

On June 7, 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants. These regulations could result in the installation of additional controls at certain of the facilities of the Company, which could result in significant capital expenditures and compliance costs that could affect future unit retirement and replacement decisions, depending on the specific technology requirements of the final rule.

The impact of these proposed rules cannot be determined at this time and will depend on the specific provisions of the final rules and the outcome of any legal challenges. These regulations could result in 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. 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.

Coal Combustion Residuals

The Company currently operates two electric generating plants in Mississippi and is also part owner of a plant located in Alabama, each with on-site coal combustion residuals storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion residuals to third parties for beneficial reuse. Historically, individual states have regulated coal combustion residuals and the States of Mississippi and Alabama each has its own regulatory requirements. 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 residuals, 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 residuals: 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 residuals 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 residuals. On September 30, 2013, the U.S. District Court for the District of Columbia issued an order granting partial summary judgment to the environmental groups and other parties, ruling that the EPA has a statutory obligation to review and revise, as necessary, the federal solid waste regulations applicable to coal combustion residuals. On January 29, 2014, the EPA filed a consent decree requiring the EPA to take final action regarding the proposed regulation of coal combustion residuals as solid waste by December 19, 2014.

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 residuals could have a material impact on the generation, management, beneficial use, and disposal of such residuals. 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.

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. The legal basis for these regulations is currently being challenged in the U.S. Supreme Court. 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 January 8, 2014, the EPA published re-proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. A Presidential memorandum issued on June 25, 2013 also directs the EPA to propose standards, regulations, or guidelines for addressing modified, reconstructed, and existing steam electric generating units by June 1, 2014.

Although the outcome of any federal, state, and international initiatives, including the EPA's proposed regulations and guidelines discussed above, will depend on the scope and specific requirements of the proposed and final rules and the outcome of any legal challenges and, therefore, 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 additional 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 CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2012 greenhouse gas emissions were approximately 7 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2013 greenhouse gas emissions on the same basis is approximately 10 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources and other factors.

FERC Matters

On May 3, 2013, the FERC accepted a settlement agreement entered into by the Company with its wholesale customers which approved, among other things, the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC for certain items. The regulatory treatment includes (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. See Note 3 to the financial statements under "FERC Matters" for more information.

PSC Matters

General

In August 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing for informational purposes only the return on equity (ROE) formulas used by the Company and all other regulated electric utilities in Mississippi. On March 14, 2013, the Mississippi Public Utilities Staff (MPUS) filed with the Mississippi PSC its report on 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.

Energy Efficiency

On July 11, 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards. Quick Start Plans, which include a portfolio of energy efficiency programs that are intended to provide benefits to a majority of customers, were required to be filed within six months of the order and will be in effect for two to three years. An annual report addressing the performance of all energy efficiency programs is required. On January 10, 2014, the Company submitted its 2014 Energy Efficiency Quick Start Plan filing, which proposed a portfolio of energy efficiency programs. The ultimate outcome of this matter cannot be determined at this time.

Performance Evaluation Plan

The Company’s retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on projected revenue requirement, and the PEP lookback filing, which is filed after the year and allows for review of actual revenue requirement compared to the projected filing.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. In May 2012, the Mississippi PSC issued an order suspending the Company's annual lookback filing for 2011. On March 15, 2013, the Company submitted its annual PEP lookback filing for 2012, which indicated a refund due to customers of $4.7 million, which was accrued in retail revenues in 2013. On May 1, 2013, the MPUS contested the filing. Unresolved matters related to certain costs included in the 2010 PEP lookback filing, which are currently under review, also impact the 2012 PEP lookback filing.

On March 5, 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.925%, or $15.3 million, annually, with the new rates effective March 19, 2013. The Company may be entitled to $3.3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

While the Company does not expect the resolution of these matters to have a material impact on its financial statements, the ultimate outcome cannot be determined at this time.

See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information.

Environmental Compliance Overview Plan

In 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 monitored by the Company and all options are 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.

In April 2012, the Mississippi PSC approved the Company's request for a CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. In May 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 Company's portion of the cost is expected to be recovered through the ECO Plan following the scheduled completion of the project in December 2015. As of December 31, 2013, total project expenditures were $320.6 million, of which the Company's portion was $162.3 million, excluding AFUDC of $8.5 million.

In June 2012, the Mississippi PSC approved the Company's 2012 ECO Plan filing, including a 0.16%, or $1.5 million, decrease in annual revenues, effective June 29, 2012. On August 13, 2013, the Mississippi PSC approved the Company’s 2013 ECO Plan filing which proposed no change in rates.

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

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; the most recent filing occurred on November 15, 2013. The Mississippi PSC approved the 2014 retail fuel cost recovery factor on January 7, 2014, with the new rates effective in February 2014. The retail fuel cost recovery factor will result in an annual increase of 3.4% of total 2013 retail revenue, or $30.1 million. At December 31, 2013, the amount of over recovered retail fuel costs included in the balance sheets was $14.5 million compared to $56.6 million at December 31, 2012. The Company also has a wholesale Municipal and Rural Associations (MRA) and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2014, the wholesale MRA fuel rate increased resulting in an annual increase of $10.1 million. Effective February 1, 2014, the wholesale MB fuel rate increased, resulting in an annual increase of $1.2 million. At December 31, 2013, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $7.3 million and $0.3 million compared to $19.0 million and $2.1 million, respectively, at December 31, 2012. In addition, at December 31, 2013, the amount of under recovered MRA emissions allowance cost included in the balance sheets was $3.8 million compared to $0.4 million at December 31, 2012. 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 cash flow.

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 2013, 2012, and 2011 audits of fuel-related expenditures were completed with no audit findings.

Ad Valorem Tax Adjustment

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On June 4, 2013, the Mississippi PSC approved an annual rate increase of 0.9%, or $7.1 million, due to an increase in ad valorem taxes resulting from the expiration of a tax exemption related to Plant Daniel Units 3 and 4. See Results of Operations – "Taxes Other Than Income Taxes" herein for additional information.

System Restoration Rider

The Company is required to make annual System Restoration Rider (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 reviewed 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 in rates 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.

For 2011, 2012, and 2013, the SRR rate was zero. The Mississippi PSC approved accruals to the property damage reserve of $3.8 million and $3.2 million in 2012 and 2013, respectively. On February 3, 2014, the Company submitted its 2014 SRR rate filing with the Mississippi PSC, which proposed that the 2014 SRR rate level remain at zero and the Company be allowed to accrue $3.3 million to the property damage reserve in 2014. The ultimate outcome of this matter cannot be determined at this time.

Storm Damage Cost Recovery

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. The total storm restoration costs incurred in 2013 were $2.3 million. At December 31, 2013, the balance in the property damage reserve was $60.1 million.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of the Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an integrated coal gasification combined cycle technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation on June 5, 2013. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Project Approval

In April 2012, the Mississippi PSC issued a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC (2012 MPSC CPCN Order), which the Sierra Club appealed to the Chancery Court. In December 2012, the Chancery Court affirmed the 2012 MPSC CPCN Order. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court. The ultimate outcome of the CPCN challenge cannot be determined at this time.

Kemper IGCC Schedule and Cost Estimate

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion, net of the DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN 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. Exceptions to the $2.88 billion cost cap include the Cost Cap Exceptions, as contemplated in the Settlement Agreement and the 2012 MPSC CPCN Order. Recovery of the Cost Cap Exception amounts remains subject to review and approval by the Mississippi PSC. The Kemper IGCC was originally scheduled to be placed in service in May 2014 and is currently scheduled to be placed in service in the fourth quarter 2014.

The Company's 2010 project estimate, current cost estimate, and actual costs incurred as of December 31, 2013 for the Kemper IGCC are as follows:

Cost Category	2010 Project Estimate[d]	Current Estimate	**Actual Costs at 12/31/2013**
		(in billions)	
Plant Subject to Cost Cap[a]	$ 2.40	$ 4.06	**$ 3.25**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.09**
AFUDC[b]	0.17	0.45	**0.28**
General Exceptions	0.05	0.10	**0.07**
Regulatory Asset[c]	—	0.09	**0.07**
Total Kemper IGCC[a]	$ 2.97	$ 5.04	**$ 3.99**

(a) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the DOE Grants and excluding the Cost Cap Exceptions.

(b) The Company's original estimate included recovery of financing costs during construction which was not approved by the Mississippi PSC in June 2012 as described in "Rate Recovery of Kemper IGCC Costs."

(c) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs - Regulatory Assets."

(d) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

Of the total costs incurred as of December 31, 2013, $2.74 billion was included in CWIP (which is net of the DOE Grants and estimated probable losses of $1.18 billion), $70.5 million in other regulatory assets, and $3.9 million in other deferred charges and assets in the balance sheet, and $1.0 million was previously expensed.

The Company does not intend to seek any rate recovery or joint owner contributions for any related costs that exceed the $2.88 billion cost cap, excluding the Cost Cap Exceptions and net of the DOE Grants. The Company recorded pre-tax charges to income for revisions to the cost estimate of $78.0 million ($48.2 million after tax) and $1.1 billion ($680.5 million after tax) in 2012 and 2013, respectively. The revised cost estimates reflect increased labor costs, piping and other material costs, start-up costs, decreases in construction labor productivity, the change in the in-service date, and an increase in the contingency for risks associated with start-up activities. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC" for additional information.

The Company could experience further construction cost increases and/or schedule extensions with respect to the Kemper IGCC as a result of factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, or non-performance under construction or other agreements. Furthermore, the Company could also experience further schedule extensions associated with start-up activities for this "first-of-a-kind" technology, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems, which would result in further cost increases and could result in the loss of certain tax benefits related to bonus depreciation. In subsequent periods, any further changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap will be reflected in the Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" for additional information regarding the Company's MRA cost based tariff relating to recovery of a portion of the Kemper IGCC costs from the Company's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See Note 3 to the financial statements under "Retail Regulatory Matters – Baseload Act" for additional information. See "Income Tax Matters – Investment Tax Credits" for information on certain tax credits related to the Kemper IGCC.

The ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, cannot be determined at this time, but could have a material impact on the Company's results of operations, financial condition, and liquidity.

2012 MPSC CPCN Order

The 2012 MPSC CPCN 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. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN.

In June 2012, the Mississippi PSC denied the Company's proposed rate schedule for recovery of financing costs during construction, 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 (2012 MPSC CWIP Order).

In July 2012, the Company appealed the Mississippi PSC's June 2012 decision to the Mississippi Supreme Court and requested interim rates under bond. In July 2012, the Mississippi Supreme Court denied the Company's request for interim rates under bond.

Settlement Agreement

On January 24, 2013, the Company entered into the Settlement Agreement with the Mississippi PSC that, among other things, establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC and dismissed the Company's appeal of the 2012 MPSC CWIP Order. Under the Settlement Agreement, the Company agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. The Settlement Agreement also allows the Company to secure alternate financing for costs that are not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the Settlement Agreement. Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law on February 26, 2013. The Company intends to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs as approved by the Mississippi PSC. The rate recovery necessary to recover the annual costs of securitization is expected to be filed and become effective after the Kemper IGCC is placed in service and following completion of the Mississippi PSC's final prudence review of costs for the Kemper IGCC.

The Settlement Agreement provides that the Company may terminate the Settlement Agreement if certain conditions 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 Company continues to work with the Mississippi PSC and the MPUS to implement the procedural schedules set forth in the Settlement Agreement and variations to the schedule are likely.

2013 MPSC Rate Order

Consistent with the terms of the Settlement Agreement, on January 25, 2013, the Company filed a new request to increase retail rates in 2013 by $172 million annually, based on projected investment for 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service.

On March 5, 2013, the Mississippi PSC issued the 2013 MPSC Rate Order, approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively are designed to collect $156 million annually beginning in 2014. Amounts collected through these rates are being recorded as a regulatory liability to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service. As of December 31, 2013, $98.1 million had been collected, with $10.3 million recognized in retail revenues in the statement of operations and the remainder deferred in other regulatory liabilities and included in the balance sheet.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi, the Company continues to record AFUDC on the Kemper IGCC during the construction period. The Company will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. The Company will continue to comply with the 2013 MPSC Rate Order by collecting and deferring the approved rates during the construction period unless directed to do otherwise by the Mississippi PSC. On March 21, 2013, a legal challenge to the 2013 MPSC Rate Order was filed by Thomas A. Blanton with the Mississippi Supreme Court, which remains pending against the Company and the Mississippi PSC.

Seven-Year Rate Plan

Also consistent with the Settlement Agreement, on February 26, 2013, the Company filed with the Mississippi PSC the proposed Seven-Year Rate Plan, which is 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.

On March 22, 2013, the Company, in compliance with the 2013 MPSC Rate Order, filed a revision to the Seven-Year Rate Plan with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020, which is still under review by the Mississippi PSC. In the Seven-Year Rate Plan, the Company proposed recovery of an annual revenue requirement of approximately $156 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. The 2013 MPSC Rate Order, which increased rates beginning on March 19, 2013, is integral to the Seven-Year Rate Plan, which contemplates amortization of the regulatory liability balance at the in-service date to be used to mitigate customer rate impacts through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the Seven-Year Rate Plan filing, the Company proposed annual rate recovery to remain the same from 2014 through 2020. At the time of the filing of the Seven-Year Rate Plan, the proposed revenue requirement approximated the forecasted cost of service for the period 2014 through 2020. Under the Company's proposal, to the extent that the actual annual cost of service differs from the forecast approved in the Seven-Year Rate Plan, the difference would be deferred as a regulatory asset or liability, subject to accrual of carrying costs, and would be included in the next year's rate recovery calculation. If any deferred balance remains at the end of the Seven-Year Rate Plan term, the Mississippi PSC will review the amount and determine the appropriate method and period of disposition.

The revenue requirements set forth in the Seven-Year Rate Plan assume the sale of a 15% undivided interest in the Kemper IGCC to SMEPA and utilization of bonus depreciation as provided by the American Taxpayer Relief Act of 2012 (ATRA), which currently requires that the Kemper IGCC be placed in service in 2014. See "Income Tax Matters – Bonus Depreciation" herein for additional information.

In 2014, the Company plans to amend the Seven-Year Rate Plan to reflect changes including the revised in-service date, the change in expected benefits relating to tax credits, various other revenue requirement items, and other tax matters, which include ensuring compliance with the normalization requirements of the Internal Revenue Code. The impact of these revisions for the average annual retail revenue requirement is estimated to be approximately $35 million through 2020. The amendment to the Seven-Year Rate Plan is also expected to reflect rate mitigation options identified by the Company that, if approved by the Mississippi PSC, would result in no change to the total customer rate impacts contemplated in the original Seven-Year Rate Plan.

Further cost increases and/or schedule extensions with respect to the Kemper IGCC could have an adverse impact on the Seven-Year Rate Plan, such as the inability to recover items considered as Cost Cap Exceptions, potential costs subject to securitization financing in excess of $1.0 billion, and the loss of certain tax benefits related to bonus depreciation. While the Kemper IGCC is scheduled to be placed in service in the fourth quarter 2014, any schedule extension beyond 2014 would result in the loss of the tax benefits related to bonus depreciation. The estimated value of the bonus depreciation tax benefits to retail customers is approximately $200 million. Loss of these tax benefits would require further adjustment to the Seven-Year Rate Plan and approval by the Mississippi PSC to ensure compliance with the normalization requirements of the Internal Revenue Code. In the event that the Mississippi PSC does not approve or the Company withdraws the Seven-Year Rate Plan, the Company would seek rate recovery through an alternate means, which could include a traditional rate case.

Prudence Reviews

The Mississippi PSC’s prudence review of Kemper IGCC costs incurred through March 31, 2013, as provided for in the Settlement Agreement, is expected to occur in the second quarter 2014. A final review of all costs incurred after March 31, 2013 is expected to be completed within six months of the Kemper IGCC’s in-service date. Furthermore, regardless of any prudence determinations made during the construction and start-up period, the Mississippi PSC has the right to make a final prudence determination after the Kemper IGCC has been placed in service.

Regulatory Assets

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, subject to review of such costs by the Mississippi PSC. The amortization period for any such costs approved for recovery 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.

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. The mine started commercial operation on June 5, 2013.

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. See Note 1 under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

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 ultimate outcome of these matters 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. In February 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. In June 2012, the Company and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. On March 29, 2013, the Company and SMEPA signed an amendment to the asset purchase agreement whereby the Company and SMEPA agreed to amend the power supply agreement entered into by the parties in April 2011 to reduce the capacity amounts to be received by SMEPA by half (approximately 75 MWs) at the sale and transfer of the undivided interest in the Kemper IGCC to SMEPA. Capacity revenues under the April 2011 power supply agreement were $17.5 million in 2013. On December 24, 2013, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014. The sale and transfer of an interest in the Kemper IGCC to SMEPA is subject to approval by the Mississippi PSC.

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

In March 2012 and subsequent to December 31, 2013, the Company received $150 million and $75 million, respectively, of interest-bearing refundable deposits from SMEPA to be applied to the purchase. While the expectation is that these amounts will be applied to the purchase price at closing, the Company would be required to refund the deposits 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 Service, 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 March 2012 deposit has been presented as a current liability in the balance sheet and as financing proceeds in the statement of cash flow. On July 18, 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposits.

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

Income Tax Matters

Bonus Depreciation

On January 2, 2013, the ATRA was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property 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 and have a positive impact on the future cash flows of the Company through 2014. The extension of 50% bonus depreciation had a positive impact on the Company's cash flows of approximately $89 million in 2013 and is expected to have a positive impact of between $560 million and $620 million in 2014. These estimated positive cash flow impacts are dependent upon placing the Kemper IGCC in service in 2014. See "Integrated

Coal Gasification Combined Cycle" for additional information on factors which could result in changes to the scheduled in-service date of the Kemper IGCC and result in the loss of the tax benefits related to bonus depreciation.

Investment Tax Credits

The Internal Revenue Service (IRS) 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. On May 15, 2013, the IRS notified the Company that no additional tax credits under the Internal Revenue Code Section 48A Phase III were allocated to the Kemper IGCC. As a result of the schedule extension for the Kemper IGCC, the Phase I credits have been recaptured. Through December 31, 2013, the Company had recorded tax benefits totaling $276.4 million for the remaining Phase II credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. A portion of the Phase II tax credits will be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described above.

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

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 residuals, 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 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, 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. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

Unbilled Revenues

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

Pension and Other Postretirement Benefits

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

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

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.3 million or less change in total annual benefit expense and a $16.5 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 6.89%, 7.04%, and 7.06% for the years ended December 31, 2013, 2012, and 2011, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment.

Kemper IGCC Estimated Construction Costs, Project Completion Date, and Rate Recovery

The Company estimates the scheduled in-service date for the Kemper IGCC to be the fourth quarter 2014 and has revised its cost estimate to complete construction above the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company does not intend to seek rate recovery or any joint owner contributions for any related costs that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. As a result of the revisions to the cost estimate, the Company recorded pretax charges of $78 million in 2012 and $1.10 billion in 2013. In subsequent periods, any further changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap will be reflected in the statements of income and these changes could be material. The Company could experience further construction cost increases and/or schedule extensions with respect to the Kemper IGCC as a result of factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, or non-performance under construction or other agreements. Furthermore, the Company could also experience further schedule extensions associated with start-up activities for this "first-of-a-kind" technology, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems, which would result in further cost increases.

Given the significant judgment involved in estimating the future costs to complete construction, the project completion date, the ultimate rate recovery for the Kemper IGCC, and the potential impact on the results of operations, the Company considers these items to be critical accounting estimates. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Although earnings in 2013 were negatively affected by revisions to the cost estimate for the Kemper IGCC, the Company's financial condition remained stable at December 31, 2013. These charges for the year ended December 31, 2013 have resulted in cash expenditures of $375.1 million with no recovery as of December 31, 2013 and are expected to result in future cash expenditures (primarily in 2014) of approximately $805 million with no recovery. In 2013, the Company received $1.1 billion in capital contributions from Southern Company. 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 2014 through 2016, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. In addition to the Kemper IGCC, projected capital expenditures in that period include investments to maintain existing 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 remained stable in value as of December 31, 2013 as compared to December 31, 2012. No contributions to the qualified pension plan were made for the year ended December 31, 2013. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2014.

Net cash provided from operating activities totaled $447.6 million for 2013, an increase of $212.2 million as compared to the corresponding period in 2012. 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, increases in rate recovery related to the Kemper IGCC, and decreases in fossil fuel stock, partially offset by a decrease in over-recovered regulatory clause revenues and an increase in regulatory assets associated with the Kemper IGCC. 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 used for investing activities totaled $1.6 billion for 2013 primarily due to gross property additions primarily related to the Kemper IGCC and the Plant Daniel scrubber, partially offset by proceeds from asset sales. 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 the DOE Grants 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 provided from financing activities totaled $1.2 billion in 2013 primarily due to an increase in capital contributions from Southern Company and an increase in long-term debt financings, partially offset by redemptions of long-term debt. 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, and the receipt of an interest bearing refundable deposit related to a pending asset sale, partially offset by redemptions of long-term debt.

Significant balance sheet changes as of December 31, 2013 compared to 2012 include an increase in total property, plant, and equipment of $585.6 million, primarily due to the Kemper IGCC, and a decrease in fossil fuel stock of $63.1 million. Prepaid income taxes, accumulated deferred income taxes, and accumulated deferred investment tax credits decreased $95.1 million, $172.2 million, and $86.3 million, respectively, primarily due to the estimated probable losses on the Kemper IGCC and the recapture of the Phase I investment tax credits. Long-term debt increased $602.6 million primarily due to the issuance of $600.0 million of bank notes and the addition of the Kemper IGCC capital lease obligation relating to the nitrogen supply agreement of $79.7 million, partially offset by $82.6 million of revenue bonds paid at maturity. Total common stockholder's equity increased $427.3 million due to a $975.1 million increase in paid-in capital, partially offset by a $548.6 million decrease in retained earnings, which was primarily due to the estimated probable losses on the Kemper IGCC. The increase in paid-in capital was primarily due to $1.1 billion in capital contributions from Southern Company.

The Company's ratio of common equity to total capitalization, excluding long-term debt due within one year, decreased from 52.3% in 2012 to 49.7% at December 31, 2013.

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. See "Capital Requirements and Contractual Obligations" herein for additional information.

The Company has received $245.3 million of DOE Grants that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for the initial operation of 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.

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 U.S. 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, 2013, the Company had approximately $145.2 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2013 were as follows:

Expires[(a)]				Executable Term-Loans		Due Within One Year	
2014	2016	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 in 2015, 2017, or 2018.

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 to other indebtedness (including guarantee obligations) of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specified threshold. 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 expects to renew its credit arrangements, as needed prior to expiration.

A portion of the $300 million unused credit arrangements with banks is allocated to 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, 2013 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:

	Commercial Paper at the End of the Period		Commercial Paper 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, 2013	**$ —**	**—%**	**$ 23**	**0.2%**	**$ 148**
December 31, 2012	$ —	—%	$ —	—%	$ —
December 31, 2011	$ —	—%	$ 7	0.2%	$ 70

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

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 November 2012, the Company entered into a 366-day $100 million aggregate principal amount floating rate bank loan bearing interest based on one-month London Interbank Offered Rate (LIBOR). The first advance in the amount of $50 million was made in November 2012. In January 2013, the second advance in the amount of $50 million was made. In September 2013, the Company amended the bank loan, which extended the maturity date to 2015. The proceeds of this loan were used for working capital and other general corporate purposes, including the Company's continuous construction program.

In March 2013, the Company entered into four two-year floating rate bank loans bearing interest based on one-month LIBOR. These term loans were for an aggregate principal amount of $300 million and proceeds were used for working capital and other general corporate purposes, including the Company's continuous construction program.

In September 2013, the Company entered into a two-year floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $125 million aggregate principal amount and proceeds were used to repay at maturity a two-year floating rate bank loan in the aggregate principal amount of $125 million.

Subsequent to December 31, 2013, the Company entered into an 18-month floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $250 million aggregate principal amount, and proceeds were used for working capital and other general corporate purposes, including the Company's continuous construction program.

These bank loans and the other revenue bonds described below 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, other hybrid securities, and securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2013, the Company was in compliance with its debt limits.

In addition, these bank loans and the other revenue bonds described below contain cross default provisions to other indebtedness (including guarantee obligations) that would be triggered if the Company defaulted on indebtedness above a specified threshold. The Company is currently in compliance with all such covenants.

Senior Notes

In November 2013, the Company's $50.0 million aggregate principal amount of Series 2008A 6.0% Senior Notes due November 15, 2013 matured. 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.

Other Revenue Bonds

In March 2013 and July 2013, the Mississippi Business Finance Corporation (MBFC) issued $15.8 million and $15.3 million, respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A. 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. In September 2013, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A of $40.07 million, Series 2012B of $21.25 million, and Series 2012C of $21.25 million were paid at maturity.

In November 2013, the MBFC entered into an agreement to issue up to $33.75 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013A (Mississippi Power Company Project) and up to $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013B (Mississippi Power Company Project) for the benefit of the Company. In November 2013, the MBFC issued $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013B 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 2013A bonds will be used for this same purpose.

Other Obligations

In March 2012 and subsequent to December 31, 2013, the Company received $150 million and $75 million, respectively, of interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the sale is closed, the deposits bear interest at the Company's AFUDC rate adjusted for income taxes, which was 9.932% per annum for 2013 and 9.967% per annum for 2012, and are 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. In July 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposits.

In September 2013, the Company entered into a nitrogen supply agreement for the air separation unit of the Kemper IGCC, which resulted in a capital lease obligation at inception of $82.9 million with an annual interest rate of 4.9%. Assets acquired under capital leases are recorded on the balance sheet as utility plant in service and the related obligations are classified as long-term debt.

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 transportation and storage, emissions allowances, and energy price risk management. At December 31, 2013, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $243 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 and subsequent to December 31, 2013, the Company received $150 million and $75 million, respectively, of interest-bearing refundable deposits 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 deposits bear interest at the Company's AFUDC rate adjusted for income taxes, which was 9.932% per annum for 2013 and 9.967% per annum for 2012, and are 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 18, 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposits.

On May 24, 2013, S&P revised the ratings outlook for Southern Company and the traditional operating companies, including the Company, from stable to negative.

On August 6, 2013, Moody's downgraded the senior unsecured debt and preferred stock ratings of the Company to Baa1 from A3 and to Baa3 from Baa2, respectively. Moody's maintained the stable ratings outlook for the Company.

On August 6, 2013, Fitch Ratings, Inc. affirmed the senior unsecured debt and preferred stock ratings of the Company and revised the ratings outlook for the Company from stable to negative.

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 $576.3 million of outstanding variable rate long-term debt at December 31, 2013 was 0.87%. 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 $5.8 million at January 1, 2014. 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 physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. 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, 2013 when compared to the December 31, 2012 reporting period.

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

	2013 Changes	2012 Changes
	Fair Value	
	(in thousands)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (16,927)**	$ (50,990)
Contracts realized or settled	**11,271**	43,326
Current period changes[(a)]	**178**	(9,263)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (5,478)**	$ (16,927)

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

The net hedge volumes of energy-related derivative contracts, all of which are natural gas swaps, for the years ended December 31 were as follows:

	2013	2012
	mmBtu* Volume	
	(in thousand)	
Total hedge volume	**56,440**	38,130

* million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.10 per mmBtu as of December 31, 2013 and $0.44 per mmBtu as of December 31, 2012. There were no options outstanding as of the reporting periods presented. The costs associated with natural gas hedges are recovered through the Company's energy cost management clauses.

At December 31, 2013 and 2012, 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 2014.

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, 2013 were as follows:

	Fair Value Measurements December 31, 2013			
	Total Fair Value	Maturity Year 1	Years 2&3	Years 4&5
	(in thousands)			
Level 1	$ —	$ —	$ —	$ —
Level 2	(5,478)	(300)	(4,020)	(1,158)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (5,478)	$ (300)	$ (4,020)	$ (1,158)

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 is currently estimated to be $757 million for 2014, $252 million for 2015, and $249 million for 2016. Included in the estimate for 2014 are expenditures related to the construction of the Kemper IGCC of $490 million, which is net of SMEPA's 15% proposed ownership share of the Kemper IGCC of approximately $555 million in 2014 (including construction costs for all prior years relating to its proposed ownership interest). Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $154 million, $108 million, and $51 million for 2014, 2015, and 2016, respectively. These estimated amounts also include capital expenditures covered under long-term service agreements.

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 and further risks related to the estimated schedule and costs and rate recovery for the Kemper IGCC.

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

	2014	2015-2016	2017-2018	After 2018	Total
			(in thousands)		
Long-term debt[(a)] —					
Principal	$ 11,250	$ 825,000	$ 35,000	$ 1,157,695	$ 2,028,945
Interest	75,050	144,598	123,159	783,899	1,126,706
Preferred stock dividends[(b)]	1,733	3,465	3,465	—	8,663
Financial derivative obligations[(c)]	3,652	5,399	1,230	—	10,281
Unrecognized tax benefits[(d)]	3,840	—	—	—	3,840
Operating leases [(e)]	10,181	2,457	513	—	13,151
Capital leases[(f)]	2,539	5,467	6,029	68,182	82,217
Purchase commitments —					
Capital[(g)]	757,255	494,179	—	—	1,251,434
Fuel[(h)]	288,228	350,996	213,902	328,345	1,181,471
Long-term service agreements[(i)]	22,512	43,181	19,045	138,755	223,493
Pension and other postretirement benefits plans[(j)]	5,779	12,101	—	—	17,880
Total	$ 1,182,019	$ 1,886,843	$ 402,343	$ 2,476,876	$ 5,948,081

(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, 2014, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Preferred 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) 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) Capital lease related to a 20-year nitrogen supply agreement for the Kemper IGCC. See Note 6 to the financial statements for additional information.

(g) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. Estimates reflect the proposed sale of 15% of the Kemper IGCC to SMEPA. At December 31, 2013, 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.

(h) 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, 2013.

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

(j) 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 2013 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, completion of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, 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 residuals, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, 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, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, 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, which includes the development and construction of facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity factors, adverse weather conditions, shortages and inconsistent quality of equipment, material, and labor, contractor or supplier delay or non-performance under construction or other agreements, delays associated with start-up activities, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems;
- ability 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 and retiree 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;
- actions related to cost recovery for the Kemper IGCC, including actions relating to proposed securitization, Mississippi PSC approval of the Company's proposed rate recovery plan, as ultimately amended, which includes the ability to complete the proposed sale of an interest in the Kemper IGCC to SMEPA, the ability to utilize bonus depreciation, which currently requires that the Kemper IGCC be placed in service in 2014, and satisfaction of requirements to utilize investment tax credits and grants;
- Mississippi PSC review of the prudence of Kemper IGCC costs;
- the outcome of any legal or regulatory proceedings regarding the Mississippi PSC's issuance of the CPCN for the Kemper IGCC, the settlement agreement between the Company and the Mississippi PSC, or the Baseload Act;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;

- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

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STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2013, 2012, and 2011
Mississippi Power Company 2013 Annual Report

	2013	2012	2011
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 799,139**	$ 747,453	$ 792,463
Wholesale revenues, non-affiliates	**293,871**	255,557	273,178
Wholesale revenues, affiliates	**34,773**	16,403	30,417
Other revenues	**17,374**	16,583	16,819
Total operating revenues	**1,145,157**	1,035,996	1,112,877
Operating Expenses:			
Fuel	**491,250**	411,226	490,415
Purchased power, non-affiliates	**5,752**	5,221	6,239
Purchased power, affiliates	**42,579**	49,907	65,574
Other operations and maintenance	**253,329**	228,675	266,395
Depreciation and amortization	**91,398**	86,510	80,337
Taxes other than income taxes	**80,694**	79,445	70,127
Estimated loss on Kemper IGCC	**1,102,000**	78,000	—
Total operating expenses	**2,067,002**	938,984	979,087
Operating Income (Loss)	**(921,845)**	97,012	133,790
Other Income and (Expense):			
Allowance for equity funds used during construction	**121,629**	64,793	24,707
Interest income	**186**	745	1,347
Interest expense, net of amounts capitalized	**(36,481)**	(40,838)	(21,691)
Other income (expense), net	**(6,216)**	519	(45)
Total other income and (expense)	**79,118**	25,219	4,318
Earnings (Loss) Before Income Taxes	**(842,727)**	122,231	138,108
Income taxes (benefit)	**(367,835)**	20,556	42,193
Net Income (Loss)	**(474,892)**	101,675	95,915
Dividends on Preferred Stock	**1,733**	1,733	1,733
Net Income (Loss) After Dividends on Preferred Stock	**$ (476,625)**	$ 99,942	$ 94,182

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

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2013, 2012, and 2011
Mississippi Power Company 2013 Annual Report

		2013		2012		2011
				(in thousands)		
Net Income (Loss)	**$**	**(474,892)**	$	101,675	$	95,915
Other comprehensive income (loss):						
Qualifying hedges:						
Changes in fair value, net of tax of $-, $(296), and $(5,494) respectively		**—**		(479)		(8,870)
Reclassification adjustment for amounts included in net income, net of tax of $526, $411, and $(18), respectively		**849**		663		(29)
Total other comprehensive income (loss)		**849**		184		(8,899)
Comprehensive Income (Loss)	**$**	**(474,043)**	$	101,859	$	87,016

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013, 2012, and 2011
Mississippi Power Company 2013 Annual Report

	2013	2012	2011
		(in thousands)	
Operating Activities:			
Net income (loss)	**$ (474,892)**	$ 101,675	$ 95,915
Adjustments to reconcile net income (loss) to net cash provided from operating activities —			
Depreciation and amortization, total	**92,465**	86,981	83,787
Deferred income taxes	**(396,400)**	17,688	71,764
Investment tax credits received	**144,036**	82,464	—
Allowance for equity funds used during construction	**(121,629)**	(64,793)	(24,707)
Pension, postretirement, and other employee benefits	**13,953**	(35,425)	3,169
Hedge settlements	**—**	(15,983)	848
Stock based compensation expense	**2,510**	2,084	1,548
Regulatory assets associated with Kemper IGCC	**(35,220)**	(15,445)	(7,719)
Estimated loss on Kemper IGCC	**1,102,000**	78,000	—
Kemper regulatory deferral	**90,524**	—	—
Other, net	**14,585**	10,516	(433)
Changes in certain current assets and liabilities —			
-Receivables	**(25,001)**	(6,589)	5,864
-Fossil fuel stock	**63,093**	(36,206)	(27,933)
-Materials and supplies	**(11,087)**	(3,473)	(2,116)
-Prepaid income taxes	**16,644**	(3,852)	12,907
-Other current assets	**(4,363)**	(19,851)	1,606
-Other accounts payable	**12,693**	8,814	24,143
-Accrued interest	**16,768**	17,627	6,817
-Accrued taxes	**11,141**	13,768	1,209
-Accrued compensation	**(6,382)**	(183)	(187)
-Over recovered regulatory clause revenues	**(58,979)**	16,836	(16,544)
-Other current liabilities	**1,109**	757	1,557
Net cash provided from operating activities	**447,568**	235,410	231,495
Investing Activities:			
Property additions	**(1,640,782)**	(1,620,047)	(964,233)
Plant acquisition	**—**	—	(84,803)
Distribution of restricted cash	**—**	—	50,000
Cost of removal net of salvage	**(10,386)**	(4,355)	(7,432)
Construction payables	**(50,000)**	78,961	97,079
Capital grant proceeds	**4,500**	13,372	232,442
Proceeds from asset sales	**79,020**	—	—
Other investing activities	**14,903**	(16,706)	(5,736)
Net cash used for investing activities	**(1,602,745)**	(1,548,775)	(682,683)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	**1,077,088**	702,971	299,305
Bonds-Other	**42,342**	51,471	—
Senior notes issuances	**—**	600,000	300,000
Interest-bearing refundable deposit related to asset sale	**—**	150,000	—
Other long-term debt issuances	**475,000**	50,000	115,000
Redemptions —			
Bonds-Other	**(82,563)**	—	—
Senior notes	**(50,000)**	(90,000)	—
Other long-term debt	**(125,000)**	(115,000)	(130,000)
Return of paid in capital	**(104,804)**	—	—
Payment of preferred stock dividends	**(1,733)**	(1,733)	(1,733)
Payment of common stock dividends	**(71,956)**	(106,800)	(75,500)
Other financing activities	**(3,040)**	5,879	(5,078)
Net cash provided from financing activities	**1,155,334**	1,246,788	501,994
Net Change in Cash and Cash Equivalents	**157**	(66,577)	50,806
Cash and Cash Equivalents at Beginning of Year	**145,008**	211,585	160,779
Cash and Cash Equivalents at End of Year	**$ 145,165**	$ 145,008	$ 211,585
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $54,118, $32,816 and $10,065 capitalized, respectively)	**$ 20,285**	$ 32,589	$ 14,814
Income taxes (net of refunds)	**(134,198)**	(77,580)	(41,024)
Noncash transactions — accrued property additions at year-end	**164,863**	214,863	135,902
Noncash transactions — capital lease obligation	**82,915**	—	—
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, 2013 and 2012
Mississippi Power Company 2013 Annual Report

Assets	2013	2012
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 145,165**	$ 145,008
Receivables —		
Customer accounts receivable	**40,978**	29,561
Unbilled revenues	**38,895**	32,688
Other accounts and notes receivable	**4,600**	7,517
Affiliated companies	**34,920**	27,160
Accumulated provision for uncollectible accounts	**(3,018)**	(373)
Fossil fuel stock, at average cost	**113,285**	176,378
Materials and supplies, at average cost	**45,347**	34,260
Other regulatory assets, current	**52,496**	55,302
Prepaid income taxes	**34,751**	129,835
Other current assets	**9,357**	17,170
Total current assets	**516,776**	654,506
Property, Plant, and Equipment:		
In service	**3,458,770**	3,036,159
Less accumulated provision for depreciation	**1,095,352**	1,065,474
Plant in service, net of depreciation	**2,363,418**	1,970,685
Construction work in progress	**2,586,031**	2,393,145
Total property, plant, and equipment	**4,949,449**	4,363,830
Other Property and Investments	**4,857**	4,887
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**139,834**	71,869
Other regulatory assets, deferred	**200,620**	236,225
Other deferred charges and assets	**36,673**	42,304
Total deferred charges and other assets	**377,127**	350,398
Total Assets	**$ 5,848,209**	$ 5,373,621

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

BALANCE SHEETS
At December 31, 2013 and 2012
Mississippi Power Company 2013 Annual Report

Liabilities and Stockholder's Equity	**2013**	2012
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 13,789**	$ 276,471
Interest-bearing refundable deposit related to asset sale	**150,000**	150,000
Accounts payable —		
Affiliated	**70,299**	54,769
Other	**210,191**	262,992
Customer deposits	**14,379**	14,202
Accrued taxes —		
Accrued income taxes	**5,590**	2,339
Other accrued taxes	**77,958**	69,376
Accrued interest	**47,144**	30,376
Accrued compensation	**9,324**	15,706
Other regulatory liabilities, current	**24,981**	5,376
Over recovered regulatory clause liabilities	**18,358**	77,338
Other current liabilities	**21,413**	31,882
Total current liabilities	**663,426**	990,827
Long-Term Debt (See accompanying statements)	**2,167,067**	1,564,462
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**72,808**	244,958
Deferred credits related to income taxes	**9,145**	10,106
Accumulated deferred investment tax credits	**284,248**	370,554
Employee benefit obligations	**94,430**	157,421
Other cost of removal obligations	**151,340**	143,461
Other regulatory liabilities, deferred	**140,880**	56,984
Other deferred credits and liabilities	**55,534**	52,860
Total deferred credits and other liabilities	**808,385**	1,036,344
Total Liabilities	**3,638,878**	3,591,633
Cumulative Redeemable Preferred Stock (See accompanying statements)	**32,780**	32,780
Common Stockholder's Equity (See accompanying statements)	**2,176,551**	1,749,208
Total Liabilities and Stockholder's Equity	**$ 5,848,209**	$ 5,373,621
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2013 and 2012
Mississippi Power Company 2013 Annual Report

	2013	2012	2013	2012
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
6.00% due 2013	$ —	$ 50,000		
2.35% due 2016	**300,000**	300,000		
5.60% due 2017	**35,000**	35,000		
1.63% to 5.55% due 2019-2042	**805,000**	805,000		
Adjustable rates (0.63% to 1.21% at 1/1/13) due 2013	**—**	226,471		
Adjustable rate (1.29% at 1/1/14) due 2014	**11,250**	—		
Adjustable rates (0.77% to 0.97% at 1/1/14) due 2015	**525,000**	—		
Total long-term notes payable	**1,676,250**	1,416,471		
Other long-term debt —				
Pollution control revenue bonds:				
5.15% due 2028	**42,625**	42,625		
Variable rates (0.04% to 0.05% at 1/1/14) 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	**82,217**	—		
Unamortized debt premium	**71,807**	80,912		
Unamortized debt discount	**(2,113)**	(9,145)		
Total long-term debt (annual interest requirement — $75 million)	**2,180,856**	1,840,933		
Less amount due within one year	**13,789**	276,471		
Long-term debt excluding amount due within one year	**2,167,067**	1,564,462	**49.6%**	46.7%
Cumulative Redeemable Preferred Stock:				
$100 par value				
Authorized: 1,244,139 shares				
Outstanding: 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $1.7 million)	**32,780**	32,780	**0.7**	1.0
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized: 1,130,000 shares				
Outstanding: 1,121,000 shares	**37,691**	37,691		
Paid-in capital	**2,376,595**	1,401,520		
Retained earnings (deficit)	**(229,871)**	318,710		
Accumulated other comprehensive income (loss)	**(7,864)**	(8,713)		
Total common stockholder's equity	**2,176,551**	1,749,208	**49.7**	52.3
Total Capitalization	**$ 4,376,398**	$ 3,346,450	**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, 2013, 2012, and 2011
Mississippi Power Company 2013 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, 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	—	—	—	99,942	—	99,942
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**	**318,710**	**(8,713)**	**1,749,208**
Net loss after dividends on preferred stock	**—**	**—**	**—**	**(476,625)**	**—**	**(476,625)**
Capital contributions from parent company	**—**	**—**	**975,075**	**—**	**—**	**975,075**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**849**	**849**
Cash dividends on common stock	**—**	**—**	**—**	**(71,956)**	**—**	**(71,956)**
Balance at December 31, 2013	**1,121**	**$ 37,691**	**$2,376,595**	**$ (229,871)**	**$ (7,864)**	**$ 2,176,551**

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

Index to the Notes to 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, 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, construction management, and power pool transactions. Costs for these services amounted to $205.0 million, $212.7 million, and $185.5 million during 2013, 2012, and 2011, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the U.S. 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 $12.5 million, $11.7 million, and $12.2 million in 2013, 2012, and 2011, respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility, which were $27.1 million, $28.1 million, and $20.9 million in 2013, 2012, and 2011, respectively. The Company also has an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs, which totaled $16.5 million, $21.2 million, and $23.3 million in 2013, 2012, and 2011, 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 2013 or 2011. The Company received storm assistance from other Southern Company subsidiaries totaling $2.0 million in 2012.

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.

Regulatory Assets and Liabilities

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

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

	2013	2012	Note
		(in thousands)	
Retiree benefit plans – regulatory assets	**$ 82,799**	$ 162,293	(a,g)
Retiree benefit plans – regulatory liabilities	**(3,111)**	—	(a,g)
Property damage	**(60,092)**	(58,789)	(i)
Deferred income tax charges	**140,185**	68,175	(c)
Property tax	**31,206**	27,882	(d)
Vacation pay	**10,214**	9,635	(e,g)
Loss on reacquired debt	**9,178**	9,815	(k)
Plant Daniel Units 3 and 4 regulatory assets	**18,821**	12,386	(j)
Other regulatory assets	**1,201**	2,035	(b)
Fuel-hedging (realized and unrealized) losses	**10,340**	20,906	(f,g)
Asset retirement obligations	**8,918**	9,353	(c)
Deferred income tax credits	**(10,191)**	(11,157)	(c)
Other cost of removal obligations	**(156,683)**	(143,461)	(c)
Fuel-hedging (realized and unrealized) gains	**(5,335)**	(2,519)	(f,g)
Kemper IGCC* regulatory assets	**75,873**	36,047	(h)
Kemper regulatory deferral	**(90,524)**	—	(h)
Other regulatory liabilities	**(409)**	—	(b)
Deferred income tax charges – Medicare subsidy	**4,214**	4,868	(l)
Total regulatory assets (liabilities), net	**$ 66,604**	$ 147,469	

* Integrated coal gasification combined cycle electric generating plant located in Kemper County, Mississippi (Kemper IGCC).
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. See Note 3 under "Ad Valorem Tax Adjustment" for additional information.

(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 four 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) Deferred and amortized over a 10-year period beginning 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 U.S. Department of Energy (DOE) transfer the remaining funds previously granted under the Clean Coal Power Initiative Round 2 (DOE Grants) from a cancelled integrated coal gasification combined cycle 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 DOE Grants funds. Through December 31, 2013, the Company has received grant funds of $245.3 million, used for the construction of the Kemper IGCC, which is reflected in the Company's financial statements as a reduction to the Kemper IGCC capital costs. An additional $25 million is expected to be received for its initial operation.

Revenues

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery, ad valorem, and environmental factors 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 22.2% of the Company's total operating revenues in 2013 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 (ITCs) 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:

	2013	2012
	(in thousands)	
Generation	**$1,475,264**	$1,363,269
Transmission	**633,903**	563,037
Distribution	**828,470**	802,718
General	**439,721**	225,723
Plant acquisition adjustment	**81,412**	81,412
Total plant in service	**$3,458,770**	$3,036,159

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 expenses except for all costs associated with operating and maintaining the lignite mine for the Kemper IGCC 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 2011, 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 $270.0 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021, bear interest at a fixed stated interest rate of 7.13% per annum, and had a fair value at the time of purchase of $346.1 million. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. 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, Depletion, and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.4% in 2013, 3.5% in 2012, and 3.9% in 2011. 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.

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.

In January 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.

The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation on June 5, 2013. Depreciation associated with fixed assets, amortization associated with rolling stock, and depletion associated with minerals and minerals rights will be recognized and charged to fuel stock and recovered through the Company's fuel clause.

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 AROs 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 AROs related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the AROs related to these assets is indeterminable and, therefore, the fair value of the AROs cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. 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:

	2013	2012
	(in thousands)	
Balance at beginning of year	**$ 42,115**	$ 19,148
Liabilities incurred	**—**	20,989
Liabilities settled	**(24)**	(282)
Accretion	**1,840**	1,874
Cash flow revisions	**(2,021)**	386
Balance at end of year	**$ 41,910**	$ 42,115

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 and is recovered 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 6.89%, 7.04%, and 7.06% for the years ended December 31, 2013, 2012, and 2011, 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. See Note 3 under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" for additional information.

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 2013, 2012, and 2011, the Company made retail accruals of $3.2 million, $3.5 million, and $3.8 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 2013, 2012, and 2011 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, mining, and generating plant materials. Materials are charged to inventory when purchased and then expensed, capitalized to plant, or charged to fuel stock, as appropriate, at weighted-average cost when utilized.

Fuel Inventory

Fuel inventory includes the average cost of coal, lignite, natural gas, oil, transportation and emissions allowances. Fuel is charged to inventory when purchased, except for the cost of owning and operating the lignite mine related to the Kemper IGCC which is charged to inventory as incurred, 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 and the wholesale rates are approved by the FERC. Emissions allowances granted by the U.S. 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 recorded in 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 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, 2013.

The Company has an ECM clause 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 December 31, 2013, the VIE consolidation resulted in an ARO and an associated liability in the amounts of $21.0 million and $22.7 million, respectively. 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. For the year ended 2011, Liberty Fuels did not have a material impact on the financial position and results of operations of the Company. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions were made to the qualified pension plan during 2013. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2014. 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, 2014, no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2010 for the 2011 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.51% and 5.39%, respectively, and an annual salary increase of 3.84%.

	2013	2012	2011
Discount rate:			
Pension plans	**5.01%**	4.26%	4.98%
Other postretirement benefit plans	**4.85**	4.04	4.87
Annual salary increase	**3.59**	3.59	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.20	8.45
Other postretirement benefit plans	**7.04**	6.96	7.53

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

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate of 7.00% for 2014, decreasing gradually to 5.00% through the year 2021 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2013 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in thousands)	
Benefit obligation	$ 4,665	$ (4,004)
Service and interest costs	224	(192)

Pension Plans

The total accumulated benefit obligation for the pension plans was $370 million at December 31, 2013 and $392 million at December 31, 2012. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2013 and 2012 were as follows:

	2013	2012
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 432,553**	$ 369,680
Service cost	**11,067**	9,416
Interest cost	**18,062**	18,019
Benefits paid	**(16,207)**	(14,949)
Actuarial (gain) loss	**(36,080)**	50,387
Balance at end of year	**409,395**	432,553
Change in plan assets		
Fair value of plan assets at beginning of year	**351,749**	282,100
Actual return on plan assets	**49,431**	39,668
Employer contributions	**2,430**	44,930
Benefits paid	**(16,207)**	(14,949)
Fair value of plan assets at end of year	**387,403**	351,749
Accrued liability	**$ (21,992)**	$ (80,804)

At December 31, 2013, the projected benefit obligations for the qualified and non-qualified pension plans were $382 million and $28 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2013 and 2012 related to the Company's pension plans consist of the following:

	2013	2012
	(in thousands)	
Prepaid pension costs	**$ 5,698**	$ —
Other regulatory assets, deferred	**77,572**	146,838
Other current liabilities	**(2,134)**	(2,087)
Employee benefit obligations	**(25,556)**	(78,717)

Presented below are the amounts included in regulatory assets at December 31, 2013 and 2012 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 2014.

	2013	2012	Estimated Amortization in 2014
		(in thousands)	
Prior service cost	**$ 4,118**	$ 5,261	$ 1,088
Net (gain) loss	**73,454**	141,577	4,937
Regulatory assets	**$ 77,572**	$ 146,838	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2013 and 2012 are presented in the following table:

	2013	2012
	(in thousands)	
Regulatory assets:		
Beginning balance	**$ 146,838**	$ 117,354
Net (gain) loss	**(58,662)**	34,893
Reclassification adjustments:		
Amortization of prior service costs	**(1,143)**	(1,309)
Amortization of net gain (loss)	**(9,461)**	(4,100)
Total reclassification adjustments	**(10,604)**	(5,409)
Total change	(69,266)	29,484
Ending balance	**$ 77,572**	$ 146,838

Components of net periodic pension cost were as follows:

	2013	2012	2011
		(in thousands)	
Service cost	**$ 11,067**	$ 9,416	$ 8,838
Interest cost	**18,062**	18,019	17,827
Expected return on plan assets	**(26,849)**	(24,121)	(25,166)
Recognized net (gain) loss	**9,461**	4,100	1,114
Net amortization	**1,143**	1,309	1,309
Net periodic pension cost	**$ 12,884**	$ 8,723	$ 3,922

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, 2013, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2014	$ 17,245
2015	18,076
2016	18,993
2017	20,172
2018	21,237
2019 to 2023	124,728

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2013 and 2012 were as follows:

	2013	2012
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 91,783**	$ 87,447
Service cost	**1,151**	1,038
Interest cost	**3,619**	4,155
Benefits paid	**(4,080)**	(4,432)
Actuarial (gain) loss	**(11,959)**	3,166
Retiree drug subsidy	**426**	409
Balance at end of year	**80,940**	91,783
Change in plan assets		
Fair value of plan assets at beginning of year	**21,990**	20,534
Actual return on plan assets	**2,379**	2,427
Employer contributions	**2,562**	3,052
Benefits paid	**(3,654)**	(4,023)
Fair value of plan assets at end of year	**23,277**	21,990
Accrued liability	**$ (57,663)**	$ (69,793)

Amounts recognized in the balance sheets at December 31, 2013 and 2012 related to the Company's other postretirement benefit plans consist of the following:

	2013	2012
	(in thousands)	
Other regulatory assets, deferred	**$ 5,227**	$ 15,454
Other regulatory liabilities, deferred	**(3,111)**	—
Employee benefit obligations	**(57,663)**	(69,793)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2013 and 2012 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 2014.

	2013	2012	Estimated Amortization in 2014
		(in thousands)	
Prior service cost	**$ (2,311)**	$ (2,498)	$ (188)
Net (gain) loss	**4,427**	17,952	—
Net regulatory assets (liabilities)	**$ 2,116**	$ 15,454	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2013 and 2012 are presented in the following table:

	2013	2012
	(in thousands)	
Net regulatory assets (liabilities):		
Beginning balance	**$ 15,454**	$ 13,324
Net (gain) loss	**(12,867)**	2,600
Reclassification adjustments:		
Amortization of transition obligation	**—**	(171)
Amortization of prior service costs	**188**	188
Amortization of net gain (loss)	**(659)**	(487)
Total reclassification adjustments	**(471)**	(470)
Total change	**(13,338)**	2,130
Ending balance	**$ 2,116**	$ 15,454

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

	2013	2012	2011
		(in thousands)	
Service cost	**$ 1,151**	$ 1,038	$ 1,012
Interest cost	**3,619**	4,155	4,292
Expected return on plan assets	**(1,472)**	(1,552)	(1,763)
Net amortization	**471**	470	274
Net periodic postretirement benefit cost	**$ 3,769**	$ 4,111	$ 3,815

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)	
2014	$ 5,051	$ (526)	$ 4,525
2015	5,335	(577)	4,758
2016	5,569	(632)	4,937
2017	5,849	(689)	5,160
2018	6,091	(748)	5,343
2019 to 2023	32,600	(3,793)	28,807

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, 2013 and 2012, along with the targeted mix of assets for each plan, is presented below:

	Target	**2013**	2012
Pension plan assets:			
Domestic equity	26%	**31%**	28%
International equity	25	**25**	24
Fixed income	23	**23**	27
Special situations	3	**1**	1
Real estate investments	14	**14**	13
Private equity	9	**6**	7
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	21%	**25%**	22%
International equity	20	**20**	19
Fixed income	38	**38**	42
Special situations	3	**1**	1
Real estate investments	11	**11**	10
Private equity	7	**5**	6
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 and interest rates, 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, 2013 and 2012. 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:

- ***Domestic and international equity.*** 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.
- ***Fixed income.*** 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.
- ***Real estate investments and private equity.*** 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, 2013 and 2012 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, 2013:	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*	$ 63,558	$ 37,206	$ —	$ 100,764
International equity*	48,829	45,146	—	93,975
Fixed income:				
U.S. Treasury, government, and agency bonds	—	26,582	—	26,582
Mortgage- and asset-backed securities	—	6,904	—	6,904
Corporate bonds	—	43,420	—	43,420
Pooled funds	—	20,905	—	20,905
Cash equivalents and other	38	9,896	—	9,934
Real estate investments	11,546	—	44,341	55,887
Private equity	—	—	25,316	25,316
Total	$ 123,971	$ 190,059	$ 69,657	$ 383,687
Liabilities:				
Derivatives	—	(115)	—	(115)
Total	$ 123,971	$ 189,944	$ 69,657	$ 383,572

* 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, 2012:	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*	$ 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.

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, 2013 and 2012 were as follows:

	2013 Real Estate Investments	**2013** Private Equity	2012 Real Estate Investments	2012 Private Equity
	(in thousands)			
Beginning balance	**$ 37,196**	**$ 26,240**	$ 32,434	$ 24,151
Actual return on investments:				
Related to investments held at year end	**3,385**	**378**	4,629	44
Related to investments sold during the year	**1,316**	**2,300**	133	3,415
Total return on investments	**4,701**	**2,678**	4,762	3,459
Purchases, sales, and settlements	**2,444**	**(3,602)**	—	(1,370)
Ending balance	**$ 44,341**	**$ 25,316**	$ 37,196	$ 26,240

The fair values of other postretirement benefit plan assets as of December 31, 2013 and 2012 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, 2013:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 3,089	$ 1,809	$ —	$ 4,898
International equity*	2,375	2,193	—	4,568
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5,213	—	5,213
Mortgage- and asset-backed securities	—	337	—	337
Corporate bonds	—	2,109	—	2,109
Pooled funds	—	1,016	—	1,016
Cash equivalents and other	1	968	—	969
Real estate investments	560	—	2,156	2,716
Private equity	—	—	1,231	1,231
Total	$ 6,025	$ 13,645	$ 3,387	$ 23,057
Liabilities:				
Derivatives	—	(5)	—	(5)
Total	$ 6,025	$ 13,640	$ 3,387	$ 23,052

* 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, 2012:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 2,561	$ 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.

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, 2013 and 2012 were as follows:

	2013 Real Estate Investments	**2013** Private Equity	2012 Real Estate Investments	2012 Private Equity
		(in thousands)		
Beginning balance	**$ 1,865**	**$ 1,293**	$ 1,851	$ 1,377
Actual return on investments:				
Related to investments held at year end	**158**	**18**	119	(1)
Related to investments sold during the year	**64**	**110**	7	90
Total return on investments	**222**	**128**	126	89
Purchases, sales, and settlements	**69**	**(190)**	(112)	(173)
Ending balance	**$ 2,156**	**$ 1,231**	$ 1,865	$ 1,293

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 2013, 2012, and 2011 were $4.1 million, $3.9 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 residuals, 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

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Alabama Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies 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 Alabama Power (including claims involving a unit co-owned by the Company) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for Alabama Power on all remaining claims and dismissal of the case with prejudice in 2011. On September 19, 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of Alabama Power, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

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.

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. Hundreds of entities have received notices from the TCEQ requesting their participation in the anticipated site remediation. The TCEQ approved the final site remediation plan in December 2013.

Amounts expensed and accrued during 2011, 2012, and 2013 related to this work were not material. 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.

In March 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 provided that base rates under the cost-based electric tariff 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 was due to a change in the recovery methodology for the return on the Kemper IGCC CWIP. 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.

In March 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. In September 2012, the Company, with its wholesale customers, filed a final settlement agreement with the FERC. On May 3, 2013, the Company received an order from the FERC accepting the settlement agreement.

On April 1, 2013, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an additional increase in the Municipal and Rural Associations (MRA) cost-based electric tariff, which was accepted by the FERC on May 30, 2013. The 2013 settlement agreement provided that base rates under the MRA cost-based electric tariff will increase by approximately $24.2 million annually, effective April 1, 2013.

Retail Regulatory Matters

General

In August 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing for informational purposes only the return on equity (ROE) formulas used by the Company and all other regulated electric utilities in Mississippi. On March 14, 2013, the Mississippi Public Utilities Staff (MPUS) filed with the Mississippi PSC its report on 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.

Energy Efficiency

On July 11, 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards. Quick Start Plans, which include a portfolio of energy efficiency programs that are intended to provide benefits to a majority of customers, were required to be filed within six months of the order and will be in effect for two to three years. An annual report addressing the performance of all energy efficiency programs is required. On January 10, 2014, the Company submitted its 2014 Energy Efficiency Quick Start Plan filing which proposed a portfolio of energy efficiency programs. The ultimate outcome of this matter cannot be determined at this time.

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. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on projected revenue requirement, and the PEP lookback filing, which is filed after the year and allows for review of actual revenue requirement compared to the projected filing. 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 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. In May 2012, the Mississippi PSC issued an order suspending the Company's annual lookback filing for 2011. On March 15, 2013, the Company submitted its annual PEP lookback filing for 2012, which indicated a refund due to customers of $4.7 million, which was accrued in retail revenues in 2013. On May 1, 2013, the MPUS contested the filing. Unresolved matters related to certain costs included in the 2010 PEP lookback filing, which are currently under review, also impact the 2012 PEP lookback filing.

On March 5, 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.925%, or $15.3 million, annually, with the new rates effective March 19, 2013. The Company may be entitled to $3.3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

While the Company does not expect the resolution of these matters to have a material impact on its financial statements, the ultimate outcome cannot be determined at this time.

Environmental Compliance Overview Plan

In 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 monitored by the Company and all options are 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.

In April 2012, the Mississippi PSC approved the Company's request for a certificate of public convenience and necessity (CPCN) to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. In May 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 Company's portion of the cost is expected to be recovered through the ECO Plan following the scheduled completion of the project in December 2015. As of December 31, 2013, total project expenditures were $320.6 million, of which the Company's portion was $162.3 million, excluding AFUDC of $8.5 million.

In June 2012, the Mississippi PSC approved the Company's 2012 ECO Plan filing, including a 0.16%, or $1.5 million, decrease in annual revenues, effective June 29, 2012. On August 13, 2013, the Mississippi PSC approved the Company's 2013 ECO Plan filing which proposed no change in rates.

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

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; the most recent filing occurred on November 15, 2013. The Mississippi PSC approved the 2014 retail fuel cost recovery factor on January 7, 2014, with the new rates effective in February 2014. The retail fuel cost recovery factor will result in an annual increase of 3.4% of total 2013 retail revenue, or $30.1 million. At December 31, 2013, the amount of over recovered retail fuel costs included in the balance sheets was $14.5 million compared to $56.6 million at December 31, 2012. The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2014, the wholesale MRA fuel rate increased resulting in an annual increase of $10.1 million. Effective February 1, 2014, the wholesale MB fuel rate increased, resulting in an annual increase of $1.2 million. At December 31, 2013, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $7.3 million and $0.3 million compared to $19.0 million and $2.1 million, respectively, at December 31, 2012. In addition, at December 31, 2013, the amount of under recovered MRA emissions allowance cost included in the balance sheets was $3.8 million compared to $0.4 million at December 31, 2012. 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 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 2013, 2012, and 2011 audits of fuel-related expenditures were completed with no audit findings.

Ad Valorem Tax Adjustment

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On June 4, 2013, the Mississippi PSC approved an annual rate increase of 0.9%, or $7.1

million, due to an increase in ad valorem taxes resulting from the expiration of a tax exemption related to Plant Daniel Units 3 and 4.

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 reviewed 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 in rates 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.

For 2011, 2012, and 2013, the SRR rate was zero. The Mississippi PSC approved accruals to the property damage reserve of $3.8 million and $3.2 million in 2012 and 2013, respectively. On February 3, 2014, the Company submitted its 2014 SRR rate filing with the Mississippi PSC, which proposed that the 2014 SRR rate level remain at zero and the Company be allowed to accrue $3.3 million to the property damage reserve in 2014. The ultimate outcome of this matter cannot be determined at this time.

Storm Damage Cost Recovery

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. The total storm restoration costs incurred in 2013 and 2012 were $2.3 million and $10.5 million, respectively. At December 31, 2013, the balance in the property damage reserve was $60.1 million.

Baseload Act

In 2008, legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi (Baseload Act) was signed by the Governor of Mississippi. 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 outcome of any legal challenges to this legislation cannot be determined at this time. See "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" herein for additional information.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of the Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an integrated coal gasification combined cycle technology with an output capacity of 582 megawatts (MWs). The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation on June 5, 2013. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Project Approval

In April 2012, the Mississippi PSC issued a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC (2012 MPSC CPCN Order), which the Sierra Club appealed to the Chancery Court. In December 2012, the Chancery Court affirmed the 2012 MPSC CPCN Order. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court. The ultimate outcome of the CPCN challenge cannot be determined at this time.

Kemper IGCC Schedule and Cost Estimate

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion, net of the $245.3 million of DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN 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. Exceptions to the $2.88 billion cost cap include the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, 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) (Cost Cap Exceptions), as contemplated in the settlement agreement between the Company and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) and the 2012 MPSC CPCN Order. Recovery of the Cost Cap Exception amounts remains subject to review and approval by the Mississippi PSC. The Kemper IGCC was originally scheduled to be placed in service in May 2014 and is currently scheduled to be placed in service in the fourth quarter 2014.

The Company's 2010 project estimate, current cost estimate, and actual costs incurred as of December 31, 2013 for the Kemper IGCC are as follows:

Cost Category	2010 Project Estimate[d]	Current Estimate	**Actual Costs at 12/31/2013**
		(in billions)	
Plant Subject to Cost Cap[a]	$ 2.40	$ 4.06	**$ 3.25**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.09**
AFUDC[b]	0.17	0.45	**0.28**
General Exceptions	0.05	0.10	**0.07**
Regulatory Asset[c]	—	0.09	**0.07**
Total Kemper IGCC[a]	$ 2.97	$ 5.04	**$ 3.99**

(a) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the DOE Grants and excluding the Cost Cap Exceptions.

(b) The Company's original estimate included recovery of financing costs during construction which was not approved by the Mississippi PSC in June 2012 as described in "Rate Recovery of Kemper IGCC Costs."

(c) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets."

(d) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

Of the total costs incurred as of December 31, 2013, $2.74 billion was included in CWIP (which is net of the DOE Grants and estimated probable losses of $1.18 billion), $70.5 million in other regulatory assets, and $3.9 million in other deferred charges and assets in the balance sheet, and $1.0 million was previously expensed.

The Company does not intend to seek any rate recovery or joint owner contributions for any related costs that exceed the $2.88 billion cost cap, excluding the Cost Cap Exceptions and net of the DOE Grants. The Company recorded pre-tax charges to income for revisions to the cost estimate of $78.0 million ($48.2 million after tax) and $1.1 billion ($680.5 million after tax) in 2012 and 2013, respectively. The revised cost estimates reflect increased labor costs, piping and other material costs, start-up costs, decreases in construction labor productivity, the change in the in-service date, and an increase in the contingency for risks associated with start-up activities.

The Company could experience further construction cost increases and/or schedule extensions with respect to the Kemper IGCC as a result of factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, or non-performance under construction or other agreements. Furthermore, the Company could also experience further schedule extensions associated with start-up activities for this "first-of-a-kind" technology, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems, which would result in further cost increases and could result in the loss of certain tax benefits related to bonus depreciation. In subsequent periods, any further changes in the estimated costs to complete construction of the Kemper

IGCC subject to the $2.88 billion cost cap will be reflected in the Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" for additional information regarding the Company's MRA cost based tariff relating to recovery of a portion of the Kemper IGCC costs from the Company's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See "Retail Regulatory Matters – Baseload Act" for additional information.

The ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, cannot be determined at this time, but could have a material impact on the Company's results of operations, financial condition, and liquidity.

2012 MPSC CPCN Order

The 2012 MPSC CPCN 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. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN.

In June 2012, the Mississippi PSC denied the Company's proposed rate schedule for recovery of financing costs during construction, 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 (2012 MPSC CWIP Order).

In July 2012, the Company appealed the Mississippi PSC's June 2012 decision to the Mississippi Supreme Court and requested interim rates under bond. In July 2012, the Mississippi Supreme Court denied the Company's request for interim rates under bond.

Settlement Agreement

On January 24, 2013, the Company entered into the Settlement Agreement with the Mississippi PSC that, among other things, establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC and dismissed the Company's appeal of the 2012 MPSC CWIP Order. Under the Settlement Agreement, the Company agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. The Settlement Agreement also allows the Company to secure alternate financing for costs that are not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the Settlement Agreement. Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law on February 26, 2013. The Company intends to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs as approved by the Mississippi PSC. The rate recovery necessary to recover the annual costs of securitization is expected to be filed and become effective after the Kemper IGCC is placed in service and following completion of the Mississippi PSC's final prudence review of costs for the Kemper IGCC.

The Settlement Agreement provides that the Company may terminate the Settlement Agreement if certain conditions 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 Company continues to work with the Mississippi PSC and the MPUS to implement the procedural schedules set forth in the Settlement Agreement and variations to the schedule are likely.

2013 MPSC Rate Order

Consistent with the terms of the Settlement Agreement, on January 25, 2013, the Company filed a new request to increase retail rates in 2013 by $172 million annually, based on projected investment for 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service.

On March 5, 2013, the Mississippi PSC issued an order (2013 MPSC Rate Order) approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively are designed to collect $156 million annually beginning in 2014. Amounts collected through these rates are being recorded as a regulatory liability to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service. As of December 31, 2013, $98.1 million had been collected, with $10.3

million recognized in retail revenues in the statement of operations and the remainder deferred in other regulatory liabilities and included in the balance sheet.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, the Company continues to record AFUDC on the Kemper IGCC during the construction period. The Company will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. The Company will continue to comply with the 2013 MPSC Rate Order by collecting and deferring the approved rates during the construction period unless directed to do otherwise by the Mississippi PSC. On March 21, 2013, a legal challenge to the 2013 MPSC Rate Order was filed by Thomas A. Blanton with the Mississippi Supreme Court, which remains pending against the Company and the Mississippi PSC.

Seven-Year Rate Plan

Also consistent with the Settlement Agreement, on February 26, 2013, the Company filed with the Mississippi PSC the proposed Seven-Year Rate Plan, which is 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.

On March 22, 2013, the Company, in compliance with the 2013 MPSC Rate Order, filed a revision to the Seven-Year Rate Plan with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020, which is still under review by the Mississippi PSC. In the Seven-Year Rate Plan, the Company proposed recovery of an annual revenue requirement of approximately $156 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. The 2013 MPSC Rate Order, which increased rates beginning on March 19, 2013, is integral to the Seven-Year Rate Plan, which contemplates amortization of the regulatory liability balance at the in-service date to be used to mitigate customer rate impacts through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the Seven-Year Rate Plan filing, the Company proposed annual rate recovery to remain the same from 2014 through 2020. At the time of the filing of the Seven-Year Rate Plan, the proposed revenue requirement approximated the forecasted cost of service for the period 2014 through 2020. Under the Company's proposal, to the extent that the actual annual cost of service differs from the forecast approved in the Seven-Year Rate Plan, the difference would be deferred as a regulatory asset or liability, subject to accrual of carrying costs, and would be included in the next year's rate recovery calculation. If any deferred balance remains at the end of the Seven-Year Rate Plan term, the Mississippi PSC will review the amount and determine the appropriate method and period of disposition.

The revenue requirements set forth in the Seven-Year Rate Plan assume the sale of a 15% undivided interest in the Kemper IGCC to SMEPA and utilization of bonus depreciation as provided by the American Taxpayer Relief Act of 2012 (ATRA), which currently requires that the Kemper IGCC be placed in service in 2014. See "Investment Tax Credits and Bonus Depreciation" herein for additional information regarding bonus depreciation.

In 2014, the Company plans to amend the Seven-Year Rate Plan to reflect changes including the revised in-service date, the change in expected benefits relating to tax credits, various other revenue requirement items, and other tax matters, which include ensuring compliance with the normalization requirements of the Internal Revenue Code. The impact of these revisions for the average annual retail revenue requirement is estimated to be approximately $35 million through 2020. The amendment to the Seven-Year Rate Plan is also expected to reflect rate mitigation options identified by the Company that, if approved by the Mississippi PSC, would result in no change to the total customer rate impacts contemplated in the original Seven-Year Rate Plan.

Further cost increases and/or schedule extensions with respect to the Kemper IGCC could have an adverse impact on the Seven-Year Rate Plan, such as the inability to recover items considered as Cost Cap Exceptions, potential costs subject to securitization financing in excess of $1.0 billion, and the loss of certain tax benefits related to bonus depreciation. While the Kemper IGCC is scheduled to be placed in service in the fourth quarter 2014, any schedule extension beyond 2014 would result in the loss of the tax benefits related to bonus depreciation. The estimated value of the bonus depreciation tax benefits to retail customers is approximately $200 million. Loss of these tax benefits would require further adjustment to the Seven-Year Rate Plan and approval by the Mississippi PSC to ensure compliance with the normalization requirements of the Internal Revenue Code. In the event that the Mississippi PSC does not approve or the Company withdraws the Seven-Year Rate Plan, the Company would seek rate recovery through an alternate means, which could include a traditional rate case.

Prudence Reviews

The Mississippi PSC's prudence review of Kemper IGCC costs incurred through March 31, 2013, as provided for in the Settlement Agreement, is expected to occur in the second quarter 2014. A final review of all costs incurred after March 31, 2013 is expected to be completed within six months of the Kemper IGCC's in-service date. Furthermore, regardless of any prudence determinations made during the construction and start-up period, the Mississippi PSC has the right to make a final prudence determination after the Kemper IGCC has been placed in service.

Regulatory Assets

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, subject to review of such costs by the Mississippi PSC. The amortization period for any such costs approved for recovery 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.

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. The mine started commercial operation on June 5, 2013.

In 2010, the Company executed a 40-year management fee contract with 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. See Note 1 under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

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 ultimate outcome of these matters 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. In February 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. In June 2012, the Company and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. On March 29, 2013, the Company and SMEPA signed an amendment to the asset purchase agreement whereby the Company and SMEPA agreed to amend the power supply agreement entered into by the parties in April 2011 to reduce the capacity amounts to be received by SMEPA by half (approximately 75 MWs) at the sale and transfer of the undivided interest in the Kemper IGCC to SMEPA. Capacity revenues under the April 2011 power supply agreement were $17.5 million in 2013. On December 24, 2013, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014. The sale and transfer of an interest in the Kemper IGCC to SMEPA is subject to approval by the Mississippi PSC.

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

In March 2012 and subsequent to December 31, 2013, the Company received $150 million and $75 million, respectively, of interest-bearing refundable deposits from SMEPA to be applied to the purchase. While the expectation is that these amounts will be applied to the purchase price at closing, the Company would be required to refund the deposits 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 Service, 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 March 2012 deposit has been presented as a current liability in the balance sheet and as financing proceeds in the statement of cash flow. On July 18, 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposits.

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

Investment Tax Credits and Bonus Depreciation

The Internal Revenue Service (IRS) 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. On May 15, 2013, the IRS notified the Company that no additional tax credits under the Internal Revenue Code Section 48A Phase III were allocated to the Kemper IGCC. As a result of the schedule extension for the Kemper IGCC, the Phase I credits have been recaptured. Through December 31, 2013, the Company had recorded tax benefits totaling $276.4 million for the remaining Phase II credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. A portion of the Phase II tax credits will be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described above.

On January 2, 2013, the ATRA was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property 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 and have a positive impact on the future cash flows of the Company of between $560 million and $620 million in 2014. These estimated positive cash flow impacts are dependent upon placing the Kemper IGCC in service in 2014. See "Rate Recovery of Kemper IGCC Costs – Seven-Year Rate Plan" herein for additional information.

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

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own, as tenants in common, Units 1 and 2 (total capacity of 500 MWs) at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2 (total capacity of 1,000 MWs) at Plant Daniel, which is located in Mississippi and operated by the Company.

At December 31, 2013, the Company's percentage ownership and investment in these jointly-owned facilities in commercial operation were as follows:

Generating Plant	Company Ownership	Plant in Service	Accumulated Depreciation	Construction Work in Progress
		(in thousands)		
Greene County				
Units 1 and 2	40%	$ 96,153	$ 49,731	$ 3,017
Daniel				
Units 1 and 2	50%	$ 299,179	$ 152,952	$ 168,539

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 Southern Company 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:

	2013	2012	2011
		(in thousands)	
Federal —			
Current	**$ 23,345**	$ 1,212	$ (27,099)
Deferred	**(342,870)**	16,994	65,206
	(319,525)	18,206	38,107
State —			
Current	**5,219**	1,656	(2,473)
Deferred	**(53,529)**	694	6,559
	(48,310)	2,350	4,086
Total	**$ (367,835)**	$ 20,556	$ 42,193

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:

	2013	2012
	(in thousands)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 371,553**	$ 385,899
Property basis differences	**130,679**	72,451
Energy cost management clause under recovered	**1,777**	9,492
Regulatory assets associated with asset retirement obligations	**16,764**	16,851
Pensions and other benefits	**23,769**	33,756
Regulatory assets associated with employee benefit obligations	**33,127**	68,717
Regulatory assets associated with the Kemper IGCC	**30,708**	10,492
Rate differential	**56,074**	27,270
Federal effect of state deferred taxes	**30,615**	—
Other	**35,583**	33,886
Total	**730,649**	658,814
Deferred tax assets —		
Federal effect of state deferred taxes	**—**	7,732
Fuel clause over recovered	**7,741**	38,955
Estimated loss on Kemper IGCC	**472,000**	31,200
Pension and other benefits	**57,999**	87,416
Property insurance	**23,693**	23,171
Premium on long-term debt	**23,736**	26,778
Unbilled fuel	**12,136**	11,642
Long-term service agreement	**—**	5,544
Asset retirement obligations	**16,764**	16,851
Interest rate hedges	**5,094**	5,644
ITC carryforward	**—**	170,938
Kemper rate factor - regulatory liability retail	**36,210**	—
Other	**18,094**	23,800
Total	**673,467**	449,671
Total deferred tax liabilities, net	**57,182**	209,143
Portion included in (accrued) prepaid income taxes, net	**15,626**	35,815
Accumulated deferred income taxes	**$ 72,808**	$ 244,958

At December 31, 2013, the tax-related regulatory assets were $144.4 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, 2013, the tax-related regulatory liabilities were $10.2 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred ITCs 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 ITCs amortized in this manner amounted to $1.2 million, $1.2 million, and $1.3 million for 2013, 2012, and 2011, respectively. At December 31, 2013, all non-Kemper IGCC ITCs available to reduce federal income taxes payable had been utilized.

In 2010, the Company began recognizing ITCs associated with the construction expenditures related to the Kemper IGCC. At December 31, 2013, the Company had $276.4 million in unamortized ITCs associated with the Kemper IGCC, which will be amortized over the life of the Kemper IGCC once placed in service and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operation in accordance with the Internal Revenue Code. A portion of the tax credits will be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC.

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 placed in service in 2013).

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

Effective Tax Rate

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

	2013	2012	2011
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.7**	1.3	1.9
Non-deductible book depreciation	**(0.1)**	0.3	0.3
AFUDC-equity	**5.0**	(18.6)	(6.3)
Other	**0.1**	(1.2)	(0.3)
Effective income tax rate	**43.7%**	16.8%	30.6%

The Company's 2013 effective tax rate increased from 2012 primarily due to the increase in estimated losses associated with the Kemper IGCC.

Unrecognized Tax Benefits

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

	2013	2012	2011
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 5,755**	$ 4,964	$ 4,288
Tax positions from current periods	**226**	1,186	1,486
Tax positions from prior periods	**(2,141)**	(26)	(810)
Settlements with taxing authorities	**—**	(369)	—
Balance at end of year	**$ 3,840**	$ 5,755	$ 4,964

The tax positions decrease from prior periods for 2013 relates to the uncertain tax position for the tax accounting method change for repairs-generation 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:

	2013	2012	2011
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 3,840**	$ 3,656	$ 4,144
Tax positions not impacting the effective tax rate	**—**	2,099	820
Balance of unrecognized tax benefits	**$ 3,840**	$ 5,755	$ 4,964

The tax positions impacting the effective tax rate for 2013 primarily relate to the State of Mississippi ITC. The tax positions not impacting the effective tax rate for 2012 related 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:

	2013	2012	2011
		(in thousands)	
Interest accrued at beginning of year	**$ 772**	$ 680	$ 413
Interest accrued during the year	**399**	92	267
Balance at end of year	**$ 1,171**	$ 772	$ 680

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 could change within 12 months. The settlement of federal and 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 finalized its audits of Southern Company's consolidated federal income tax returns through 2011. Southern Company has filed its 2012 federal income tax return and has received a full acceptance letter from the IRS; however, the IRS has not finalized its audit. For tax years 2012 and 2013, Southern Company was 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

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, on April 30, 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. On September 19, 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company is currently reviewing this new guidance. The ultimate outcome of this matter cannot be determined at this time; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Bank Term Loans

In November 2012, the Company entered into a 366-day $100 million aggregate principal amount floating rate bank loan bearing interest based on one-month London Interbank Offered Rate (LIBOR). The first advance in the amount of $50 million was made in November 2012. In January 2013, the second advance in the amount of $50 million was made. In September 2013, the Company amended the bank loan, which extended the maturity date to 2015. The proceeds of this loan were used for working capital and for other general corporate purposes, including the Company's continuous construction program.

In March 2013, the Company entered into four two-year floating rate bank loans bearing interest based on one-month LIBOR. These term loans were for an aggregate principal amount of $300 million and proceeds were used for working capital and other general corporate purposes, including the Company's continuous construction program.

In September 2013, the Company entered into a two-year floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $125 million aggregate principal amount and proceeds were used to repay at maturity a two-year floating rate bank loan in the aggregate principal amount of $125 million.

Subsequent to December 31, 2013, the Company entered into an 18-month floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $250 million aggregate principal amount and proceeds were used for working capital and other general corporate purposes, including the Company’s continuous construction program.

At December 31, 2013 and 2012, the Company had $525 million, which is reflected in the statements of capitalization as long-term debt, and $175 million of bank loans outstanding, respectively.

These bank loans and the other revenue bonds described below 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, other hybrid securities, and securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2013, the Company was in compliance with its debt limits.

Senior Notes

In November 2013, the Company's $50 million aggregate principal amount of Series 2008A 6.0% Senior Notes due November 15, 2013 matured. At December 31, 2013 and 2012, the Company had $1.1 billion of senior notes outstanding. 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 2011, in connection with the Company's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, the Company assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor as described in Note 1 under "Purchase of the Plant Daniel Combined Cycle Generating Units" herein. These bonds are secured by Plant Daniel Units 3 and 4 and certain personal property. The bonds were recorded at fair value as of the date of assumption, or $346.1 million, reflecting a premium of $76.1 million.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2013 and 2012 was as follows:

	2013	2012
	(in millions)	
Senior notes	**$ —**	$ 50.0
Bank term loans	**—**	175.0
Revenue bonds	**11.3**	51.5
Capitalized leases	**2.5**	—
Outstanding at December 31	**$ 13.8**	$ 276.5

Maturities through 2018 applicable to total long-term debt are as follows: $13.8 million in 2014, $527.7 million in 2015, $302.8 million in 2016, $37.9 million in 2017, and $3.1 million in 2018.

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, 2013 and 2012 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 March 2013 and July 2013, the Mississippi Business Finance Corporation (MBFC) issued $15.8 million and $15.3 million, respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A. 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.

In September 2013, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A of $40.07 million, Series 2012B of $21.25 million, and Series 2012C of $21.25 million were paid at maturity.

In November 2013, the MBFC entered into an agreement to issue up to $33.75 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013A (Mississippi Power Company Project) and up to $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013B (Mississippi Power Company Project) for the benefit of the company. In November 2013, the MBFC issued $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013B 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 2013A 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, 2013 and 2012, and $11.3 million and $51.5 million of such obligations related to taxable revenue bonds outstanding at December 31, 2013 and 2012, respectively. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Capital Leases

In September 2013, the Company entered into an agreement to sell the air separation unit for the Kemper IGCC and also entered into a 20-year nitrogen supply agreement. The nitrogen supply agreement was determined to be a sale/leaseback agreement which resulted in a capital lease obligation for the Company at inception of $82.9 million with an annual interest rate of 4.9%. There are no contingent rentals in the contract and a portion of the monthly payment specified in the agreement is related to executory costs for the operation and maintenance of the air separation unit and excluded from the minimum lease payments. The minimum lease payments for 2013 were $1.8 million and will be $6.5 million each year thereafter. As of December 31, 2013, no amortization expense had been incurred associated with the capital lease due to the Kemper IGCC not yet being in service.

Other Obligations

In March 2012 and subsequent to December 31, 2013, the Company received $150 million and $75 million, respectively, interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the sale is closed, the deposits bear interest at the Company's AFUDC rate adjusted for income taxes, which was 9.932% per annum for 2013 and 9.967% per annum for 2012, and are 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, 2013, committed credit arrangements with banks were as follows:

Expires[a]				Executable Term-Loans		Due Within One Year	
2014	2016	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 in 2015, 2017, or 2018.

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 and securitized debt relating to the securitization of certain costs of the Kemper IGCC.

A portion of the $300 million unused credit arrangements with banks is allocated to 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, 2013 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, 2013 and 2012, 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 and delivery of fossil fuel which are not recognized on the balance sheets. In 2013, 2012, and 2011, the Company incurred fuel expense of $491.3 million, $411.2 million, and $490.4 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 associated with a 40-year management contract with Liberty Fuels related to the Kemper IGCC with the remaining amount due at December 31, 2013 of $38.7 million. 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. 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 $10.1 million, $11.1 million, and $32.6 million for 2013, 2012, and 2011 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 $3.1 million in 2013, $3.6 million in 2012, and $2.6 million in 2011. The Company's annual railcar lease payments for 2014 through 2017 will average approximately $1.4 million. The Company has no lease obligation for the period 2018 and thereafter.

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 2013, $0.2 million in 2012, and $0.4 million in 2011. The Company's annual lease payment for 2014 is expected to be $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 $6.7 million in 2013, $7.3 million in 2012, and $7.5 million in 2011 related to barges and tow/shift boats. The Company's annual lease payment for 2014 with respect to these barge transportation leases is expected to be $7.6 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, 2013, there were 236 current and former employees of the Company participating in the stock option program and there were 28 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. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

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	**2013**	2012	2011
Expected volatility	**16.6%**	17.7%	17.5%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**0.9%**	0.9%	2.3%
Dividend yield	**4.4%**	4.2%	4.8%
Weighted average grant-date fair value	**$2.93**	$3.39	$3.23

The Company's activity in the stock option program for 2013 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2012	1,373,566	$ 36.34
Granted	345,830	44.03
Exercised	(379,933)	33.59
Cancelled	(5,870)	44.94
Outstanding at December 31, 2013	**1,333,593**	**$ 39.08**
Exercisable at December 31, 2013	**898,518**	**$ 37.02**

The number of stock options vested, and expected to vest in the future, as of December 31, 2013 was not significantly different from the number of stock options outstanding at December 31, 2013 as stated above. As of December 31, 2013, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and four years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $4.6 million and $4.4 million, respectively.

As of December 31, 2013, 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 10 months.

For the years ended December 31, 2013, 2012, and 2011, total compensation cost for stock option awards recognized in income was $1.0 million, $0.9 million, and $0.8 million, respectively, with the related tax benefit also recognized in income of $0.4 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, 2013, 2012, and 2011 was $2.7 million, $4.9 million, and $4.2 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.1 million, $1.9 million, and $1.6 million for the years ended December 31, 2013, 2012, and 2011, 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	**2013**	2012	2011
Expected volatility	**12.0%**	16.0%	19.2%
Expected term *(in years)*	**3.0**	3.0	3.0
Interest rate	**0.4%**	0.4%	1.4%
Annualized dividend rate	**$1.96**	$1.89	$1.82
Weighted average grant-date fair value	**$40.50**	$41.99	$35.97

Total unvested performance share units outstanding as of December 31, 2012 were 68,486. During 2013, 36,769 performance share units were granted, 48,019 performance share units were vested, and 15,699 performance share units were forfeited resulting in 41,537 unvested units outstanding at December 31, 2013. In January 2014, the vested performance share award units were converted into 14,341 shares outstanding at a share price of $41.27 for the three-year performance and vesting period ended December 31, 2013.

For the years ended December 31, 2013, 2012, and 2011, total compensation cost for performance share units recognized in income was $1.5 million, $1.2 million, and $0.7 million, respectively, with the related tax benefit also recognized in income of $0.6 million, $0.4 million, and $0.3 million, respectively. As of December 31, 2013, there was $1.7 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, 2013, 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, 2013:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 4,803	$ —	$ 4,803
Cash equivalents	125,000	—	—	125,000
Total	$ 125,000	$ 4,803	$ —	$ 129,803
Liabilities:				
Energy-related derivatives	$ —	$ 10,281	$ —	$ 10,281
Foreign currency derivatives	—	1	—	1
Total	$ —	$ 10,282	$ —	$ 10,282

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
Cash equivalents	125,600	—	—	125,600
Total	$ 125,600	$ 2,519	$ —	$ 128,119
Liabilities:				
Energy-related derivatives	$ —	$ 19,446	$ —	$ 19,446
Foreign currency derivatives	—	37	—	37
Total	$ —	$ 19,483	$ —	$ 19,483

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 Overnight Index Swap 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, 2013 and 2012, 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, 2013:	*(in thousands)*			
Cash equivalents:				
Money market funds	$ 125,000	None	Daily	Not applicable
As of December 31, 2012:				
Cash equivalents:				
Money market funds	$ 125,600	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, 2013 and 2012, 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:		
2013	**$ 2,098,639**	**$ 2,045,519**
2012	$ 1,840,933	$ 1,956,799

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. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities and the cash impacts of settled foreign currency derivatives are recorded as investing activities.

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, 2013, 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:

Net Purchased mmBtu*	Longest Hedge Date	Longest Non-Hedge Date
(in millions)		
56	2017	—

* mmBtu — million British thermal units

Interest Rate Derivatives

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

At December 31, 2013, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2014 are $1.4 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2022.

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 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, 2013, the foreign currency derivatives outstanding were immaterial.

Derivative Financial Statement Presentation and Amounts

At December 31, 2013 and 2012, 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**	**2013**	2012	**Balance Sheet Location**	**2013**	2012
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 3,352**	$ 638	Liabilities from risk management activities	**$ 3,652**	$ 13,116
	Other deferred charges and assets	**1,451**	1,881	Other deferred credits and liabilities	**6,629**	6,330
Total derivatives designated as hedging instruments for regulatory purposes		**$ 4,803**	$ 2,519		**$ 10,281**	$ 19,446
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Foreign currency derivatives:	Other current assets	**$ —**	$ —	Liabilities from risk management activities	**$ 1**	$ —
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**—**	37
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ —**	$ —		**$ 1**	$ 37
Total		**$ 4,803**	$ 2,519		**$ 10,282**	$ 19,483

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

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2013 and 2012 are presented in the following tables.

	Fair Value				
Assets	**2013**	2012	**Liabilities**	**2013**	2012
	(in thousands)			*(in thousands)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 4,803**	$ 2,519	Energy-related derivatives presented in the Balance Sheet [(a)]	**$10,281**	$19,446
Gross amounts not offset in the Balance Sheet [(b)]	**(3,856)**	(2,333)	Gross amounts not offset in the Balance Sheet [(b)]	**(3,856)**	(2,333)
Net-energy related derivative assets	**$ 947**	$ 186	**Net-energy related derivative liabilities**	**$ 6,425**	$17,113

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.
(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2013 and 2012, 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**	**2013**	2012	**Balance Sheet Location**	**2013**	2012
		(in thousands)			*(in thousands)*	
Energy-related derivatives:						
	Other regulatory assets, current	**$ (3,652)**	$ (13,116)	Other regulatory liabilities, current	**$ 3,352**	$ 638
	Other regulatory assets, deferred	**(6,629)**	(6,330)	Other regulatory liabilities, deferred	**1,451**	1,881
Total energy-related derivative gains (losses)		**$ (10,281)**	$ (19,446)		**$ 4,803**	$ 2,519

For the years ended December 31, 2013, 2012, and 2011, 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	**2013**	2012	2011	**Statements of Income Location**	**2013**	2012	2011
		(in thousands)				*(in thousands)*	
Energy-related derivatives	**$ —**	$ —	$ (3)	Fuel	**$ —**	$ —	$ —
Interest rate derivatives	**—**	(774)	(14,361)	Interest Expense	**(1,375)**	(1,073)	48
Total	**$ —**	$ (774)	$ (14,364)		**$ (1,375)**	$ (1,073)	$ 48

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

For the years ended December 31, 2013, 2012, and 2011, 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, 2013, the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on the Company's statements of income were immaterial. For the year ended December 31, 2012, the pre-tax effect of foreign currency derivatives designated as fair value hedging instruments, which include a pre-tax loss associated with the de-designated hedges prior to de-designation, was a $0.6 million gain. For the year ended December 31, 2011, the pre-tax loss was $3.6 million. These amounts were offset by changes in the fair value of the purchase commitment related to equipment purchases. Therefore, there is no impact on the Company's statements of income.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2013, the fair value of derivative liabilities with contingent features was $1.5 million.

At December 31, 2013, 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 $8.8 million. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

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.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. 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. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2013 and 2012 is as follows:

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) After Dividends on Preferred Stock
		(in thousands)	
March 2013	**$ 245,934**	**$ (429,148)**	**$ (246,321)**
June 2013	**306,435**	**(388,395)**	**(219,110)**
September 2013	**325,206**	**(79,890)**	**(24,115)**
December 2013	**267,582**	**(24,412)**	**12,921**
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 (Restated)	235,779	(46,338)	(14,965)

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

SELECTED FINANCIAL AND OPERATING DATA 2009-2013
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	2013	2012	2011	2010	2009
Operating Revenues (in thousands)	**$ 1,145,157**	$ 1,035,996	$ 1,112,877	$ 1,143,068	$ 1,149,421
Net Income (Loss) After Dividends on Preferred Stock (in thousands)	**$ (476,625)**	$ 99,942	$ 94,182	$ 80,217	$ 84,967
Cash Dividends on Common Stock (in thousands)	**$ 71,956**	$ 106,800	$ 75,500	$ 68,600	$ 68,500
Return on Average Common Equity (percent)	**(24.28)**	7.14	10.54	11.49	13.12
Total Assets (in thousands)	**$ 5,848,209**	$ 5,373,621	$ 3,671,842	$ 2,476,321	$ 2,072,681
Gross Property Additions (in thousands)	**$ 1,773,332**	$ 1,665,498	$ 1,205,704	$ 340,162	$ 95,573
Capitalization (in thousands):					
Common stock equity	**$ 2,176,551**	$ 1,749,208	$ 1,049,217	$ 737,368	$ 658,522
Redeemable preferred stock	**32,780**	32,780	32,780	32,780	32,780
Long-term debt	**2,167,067**	1,564,462	1,103,596	462,032	493,480
Total (excluding amounts due within one year)	**$ 4,376,398**	$ 3,346,450	$ 2,185,593	$ 1,232,180	$ 1,184,782
Capitalization Ratios (percent):					
Common stock equity	**49.7**	52.3	48.0	59.8	55.6
Redeemable preferred stock	**0.7**	1.0	1.5	2.7	2.8
Long-term debt	**49.6**	46.7	50.5	37.5	41.6
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**152,585**	152,265	151,805	151,944	151,375
Commercial	**33,250**	33,112	33,200	33,121	33,147
Industrial	**480**	472	496	504	513
Other	**175**	175	175	187	180
Total	**186,490**	186,024	185,676	185,756	185,215
Employees (year-end)	**1,344**	1,281	1,264	1,280	1,285

	2013	2012	2011	2010	2009
Operating Revenues (in thousands):					
Residential	**$ 241,956**	$ 226,847	$ 246,510	$ 256,994	$ 245,357
Commercial	**265,506**	250,860	263,256	266,406	269,423
Industrial	**289,272**	262,978	275,752	267,588	269,128
Other	**2,405**	6,768	6,945	6,924	7,041
Total retail	**799,139**	747,453	792,463	797,912	790,949
Wholesale — non-affiliates	**293,871**	255,557	273,178	287,917	299,268
Wholesale — affiliates	**34,773**	16,403	30,417	41,614	44,546
Total revenues from sales of electricity	**1,127,783**	1,019,413	1,096,058	1,127,443	1,134,763
Other revenues	**17,374**	16,583	16,819	15,625	14,658
Total	**$ 1,145,157**	$ 1,035,996	$ 1,112,877	$ 1,143,068	$ 1,149,421
Kilowatt-Hour Sales (in thousands):					
Residential	**2,087,704**	2,045,999	2,162,419	2,296,157	2,091,825
Commercial	**2,864,947**	2,915,934	2,870,714	2,921,942	2,851,248
Industrial	**4,738,714**	4,701,681	4,586,356	4,466,560	4,329,924
Other	**40,139**	38,588	38,684	38,570	38,855
Total retail	**9,731,504**	9,702,202	9,658,173	9,723,229	9,311,852
Wholesale — non-affiliates	**3,929,177**	3,818,773	4,009,637	4,284,289	4,651,606
Wholesale — affiliates	**931,153**	571,908	648,772	774,375	839,372
Total	**14,591,834**	14,092,883	14,316,582	14,781,893	14,802,830
Average Revenue Per Kilowatt-Hour (cents)**:					
Residential	**11.59**	11.09	11.40	11.19	11.73
Commercial	**9.27**	8.60	9.17	9.12	9.45
Industrial	**6.10**	5.59	6.01	5.99	6.22
Total retail	**8.21**	7.70	8.21	8.21	8.49
Wholesale	**6.76**	6.19	6.52	6.51	6.26
Total sales	**7.73**	7.23	7.66	7.63	7.67
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,680**	13,426	14,229	15,130	13,762
Residential Average Annual Revenue Per Customer	**$ 1,585**	$ 1,489	$ 1,622	$ 1,693	$ 1,614
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**3,088**	3,088	3,156	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,083**	2,168	2,618	2,792	2,392
Summer	**2,352**	2,435	2,462	2,638	2,522
Annual Load Factor (percent)	**64.7**	61.9	59.1	57.9	60.7
Plant Availability Fossil-Steam (percent)*	**89.3**	91.5	87.7	93.8	94.1
Source of Energy Supply (percent):					
Coal	**32.7**	22.8	34.9	43.0	40.0
Oil and gas	**57.1**	63.9	51.5	41.9	43.6
Purchased power -					
From non-affiliates	**2.0**	2.0	1.4	1.3	3.3
From affiliates	**8.2**	11.3	12.2	13.8	13.1
Total	**100.0**	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.
** The average revenue per kilowatt-hour (cents) is based on booked operating revenues and will not match billed revenue per kilowatt-hour.

DIRECTORS AND OFFICERS
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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
(Retired effective 5/20/2013)
President and Chief Executive Officer
Mississippi Power Company
Gulfport, Mississippi. Elected 2010

Thomas A. Dews
(Elected effective 10/1/2013)
President
C. L. Dews & Sons Foundry & Machinery Co., Inc.
Hattiesburg, Mississippi.

G. Edison Holland, Jr.
(Elected effective 5/20/2013)
President, Chief Executive Officer, and Chairman of the Board of Directors
Mississippi Power Company
Gulfport, Mississippi.

Mark E. Keenum
(Elected effective 10/1/2013)
President
Mississippi State University
Mississippi State, Mississippi.

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

Philip J. Terrell, Ph.D.
Retired Superintendent of Schools
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, Chief Executive Officer, and Chairman of the Board of Directors
(Retired effective 5/20/2013)

G. Edison Holland, Jr.
President, Chief Executive Officer, and Chairman of the Board of Directors
(Elected effective 5/20/2013)

Thomas O. Anderson, IV
Vice President of Generation Development
(Retired effective 5/31/2013)

John W. Atherton
Vice President of Corporate Services and Community Relations

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

Jeff G. Franklin
Vice President of Customer Services Organization

John C. Huggins
Vice President of Generation Development
(Elected effective 6/8/2013)

R. Allen Reaves
Vice President and Senior Production Officer

Billy F. Thornton
Vice President of Legislative and Regulatory Affairs

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 186,500 customers within its service area of more than 11,000 square miles in southeast Mississippi. In 2013, retail energy sales accounted for 66.7% of the Company's total sales of 14.6 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 Inc.
P.O. Box 30170
College Station, TX 77842-3170
(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 The 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	2013	2012
	(in thousands)	
First	$44,190	$26,700
Second	44,190	26,700
Third	44,190	26,700
Fourth	44,190	26,700

Number of Preferred Shareholders of record as of December 31, 2013 was 190.

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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