MISSISSIPPI POWER COMPANY

2016 ANNUAL REPORT

Mississippi Power

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2016 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 (2013)* 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, 2016.

Anthony L. Wilson
Chairman, President, and Chief Executive Officer

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

February 21, 2017

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, 2016 and 2015, and the related statements of operations, comprehensive income (loss), common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2016. 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 45 to 93) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the financial statements, the Mississippi Public Service Commission rate recovery process associated with the Kemper Integrated Coal Gasification Combined Cycle Project may have a material impact on the Company's financial statements.

Deloitte & Touche LLP

Atlanta, Georgia
February 21, 2017

DEFINITIONS

Term	Meaning
2012 MPSC CPCN Order	A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of the Kemper IGCC
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Baseload Act	State of Mississippi legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
DOE	U.S. Department of Energy
ECM	Energy cost management clause
ECO	Environmental compliance overview
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IRS	Internal Revenue Service
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mirror CWIP	A regulatory liability used by Mississippi Power to record customer refunds resulting from a 2015 Mississippi PSC order
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MRA	Municipal and Rural Associations
MW	Megawatt
OCI	Other comprehensive income
PEP	Performance evaluation plan
Plant Daniel Units 3 and 4	Combined cycle Units 3 and 4 at Plant Daniel
power pool	The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission

DEFINITIONS
(continued)

Term	Meaning
ROE	Return on equity
S&P	S&P Global Ratings, a division of S&P Global Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SMEPA	South Mississippi Electric Power Association (now known as Cooperative Energy)
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern LINC, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
SRR	System Restoration Rider
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power Company

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Mississippi Power Company 2016 Annual Report

OVERVIEW

Business Activities

Mississippi Power Company (the Company) operates as a vertically integrated utility providing electric service 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 providing electric service. These factors include the Company's ability to maintain and grow energy sales and to operate in a constructive regulatory environment that provides timely recovery of prudently-incurred costs. These costs include those related to the completion and operation of the Kemper IGCC, projected long-term demand growth, reliability, fuel, and stringent environmental standards, as well as ongoing capital expenditures required for maintenance and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

The Company continues to progress toward completing the construction and start-up of the Kemper IGCC, which was approved by the Mississippi PSC in the 2010 CPCN proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding 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 customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The current cost estimate for the Kemper IGCC in total is approximately $6.99 billion, which includes approximately $5.64 billion of costs subject to the construction cost cap and is net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants), which are expected to be used to reduce future rate impacts to customers. The Company does not intend to seek any rate recovery for any related costs that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate subject to the construction cost cap totaling $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016, 2015, and 2014, respectively. Since 2012, in the aggregate, the Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016. The current cost estimate includes costs through March 15, 2017.

In addition to the current construction cost estimate, the Company is identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap. Any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of income and these changes could be material.

The expected completion date of the Kemper IGCC at the time of the Mississippi PSC's approval in 2010 was May 2014. The combined cycle and the associated common facilities portion of the Kemper IGCC were placed in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." The Company achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. The Company subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced and captured CO_2, and has produced sulfuric acid and ammonia, all of acceptable quality under the related off-take agreements. On February 20, 2017, the Company determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, the Company currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.

Upon placing the remainder of the plant in service, the Company will be primarily focused on completing the regulatory cost recovery process. In December 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), based on a stipulation

(2015 Stipulation) between the Company and the MPUS, authorizing rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service.

On August 17, 2016, the Mississippi PSC established a discovery docket to manage all filings related to Kemper IGCC prudence issues. On October 3, 2016 and November 17, 2016, the Company made filings in this docket including a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate.

In the fourth quarter 2016, as a part of the Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected. As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings, on February 21, 2017, the Company filed an updated project economic viability analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

After the remainder of the plant is placed in service, AFUDC equity of approximately $11 million per month will no longer be recorded in income, and the Company expects to incur approximately $25 million per month in depreciation, taxes, operations and maintenance expenses, interest expense, and regulatory costs in excess of current rates. The Company expects to file a request for authority from the Mississippi PSC and the FERC to defer all Kemper IGCC costs incurred after the in-service date that cannot be capitalized, are not included in current rates, and are not required to be charged against earnings as a result of the $2.88 billion cost cap until such time as the Mississippi PSC completes its review and includes the resulting allowable costs in rates. In the event that the Mississippi PSC does not grant the Company's request for an accounting order, these monthly expenses will be charged to income as incurred and will not be recoverable through rates. The ultimate outcome of this matter cannot now be determined but could have a material impact on the Company's result of operations, financial condition, and liquidity.

The Company is required to file a rate case to address Kemper IGCC cost recovery by June 3, 2017 (2017 Rate Case). Costs incurred through December 31, 2016 totaled $6.73 billion, net of the Initial and Additional DOE Grants. Of this total, $2.76 billion of costs has been recognized through income as a result of the $2.88 billion cost cap, $0.83 billion is included in retail and wholesale rates for the assets in service, and the remainder will be the subject of the 2017 Rate Case to be filed with the Mississippi PSC and expected subsequent wholesale MRA rate filing with the FERC. The Company continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. The Company also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein, these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs, net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, the Company is developing both a traditional rate case requesting full cost recovery of the $3.31 billion (net of $137 million in Additional DOE Grants) not currently in rates and a rate mitigation plan that together represent the Company's probable filing strategy. The Company also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both the Company and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on the Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, the Company intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

The Company has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017. Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of these matters cannot now be determined but could result in further charges that could have a material impact on the Company's results of operations, financial condition, and liquidity.

Southern Company and the Company are defendants in various lawsuits that allege improper disclosure about the Kemper IGCC. While the Company believes that these lawsuits are without merit, an adverse outcome could have a material impact on the Company's results of operations, financial condition, and liquidity. In addition, the SEC is conducting a formal investigation of Southern Company and the Company concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company and the Company believe the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and "Other Matters" herein for additional information.

As of December 31, 2016, the Company's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. The Company expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, the Company intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, the Company has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, the Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company, consistent with the requirements of ASU 2014-15 (as defined herein). See FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" herein and Notes 1 and 6 to the financial statements for additional information.

The Company continues to focus on several key performance indicators, including the construction, start-up, and rate recovery of the Kemper IGCC.

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 to evaluate the Company's results and generally targets the top quartile in measuring performance.

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

Earnings

The Company's net loss after dividends on preferred stock was $50 million in 2016 compared to $8 million in 2015. The change in 2016 was primarily the result of higher pre-tax charges of $428 million ($264 million after tax) in 2016 compared to pre-tax charges of $365 million ($226 million after tax) in 2015 for estimated losses on the Kemper IGCC. The decrease in net income was partially offset by an increase in retail revenues due to the implementation of rates in September 2015 for certain Kemper IGCC in-service assets, partially offset by a decrease in wholesale revenues. The increase in revenues was partially offset by an increase in interest expense in 2016 compared to 2015 due to the termination of an asset purchase agreement between the Company and SMEPA in May 2015 and an increase in operations and maintenance expenses.

The Company's net loss after dividends on preferred stock was $8 million in 2015 compared to $329 million in 2014. The change in 2015 was primarily the result of lower pre-tax charges of $365 million ($226 million after tax) in 2015 compared to pre-tax charges of $868 million ($536 million after tax) in 2014 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 Initial DOE Grants and excluding the Cost Cap Exceptions. The reduction in net loss was also related to an increase in retail base revenues, due to the implementation of rates for certain Kemper IGCC assets placed in service that became effective with the first billing cycle in September (on August 19), and a decrease in interest expense primarily due to the termination of an asset purchase agreement between the Company and SMEPA in May 2015, partially offset by increases in income taxes due to a reduced net loss.

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

RESULTS OF OPERATIONS

A condensed statement of operations follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	**2016**	2015
		(in millions)	
Operating revenues	**$ 1,163**	**$ 25**	$ (105)
Fuel	**343**	**(100)**	(131)
Purchased power	**34**	**22**	(31)
Other operations and maintenance	**312**	**38**	3
Depreciation and amortization	**132**	**9**	26
Taxes other than income taxes	**109**	**15**	15
Estimated loss on Kemper IGCC	**428**	**63**	(503)
Total operating expenses	**1,358**	**47**	(621)
Operating income	**(195)**	**(22)**	516
Allowance for equity funds used during construction	**124**	**14**	(26)
Interest expense, net of amounts capitalized	**74**	**67**	(38)
Other income (expense), net	**(7)**	**1**	6
Income taxes (benefit)	**(104)**	**(32)**	213
Net income (loss)	**(48)**	**(42)**	321
Dividends on preferred stock	**2**	**—**	—
Net loss after dividends on preferred stock	**$ (50)**	**$ (42)**	$ 321

Operating Revenues

Operating revenues for 2016 were $1.2 billion, reflecting a $25 million increase from 2015. Details of operating revenues were as follows:

	Amount	
	2016	2015
	(in millions)	
Retail — prior year	**$ 776**	$ 795
Estimated change resulting from —		
Rates and pricing	**96**	61
Sales decline	**(4)**	(3)
Weather	**8**	(1)
Fuel and other cost recovery	**(17)**	(76)
Retail — current year	**859**	776
Wholesale revenues —		
Non-affiliates	**261**	270
Affiliates	**26**	76
Total wholesale revenues	**287**	346
Other operating revenues	**17**	16
Total operating revenues	**$ 1,163**	$ 1,138
Percent change	**2.2%**	(8.4)%

Total retail revenues for 2016 increased $83 million, or 10.7%, compared to 2015 primarily due to changes in rates and pricing of $96 million partially offset by a net decrease in fuel and other cost recovery of $17 million. Total retail revenues for 2015 decreased $19 million, or 2.4%, compared to 2014 primarily due to a lower fuel cost recovery. This decrease was partially offset by changes in rates and pricing of $61 million.

Revenues associated with changes in rates and pricing increased $96 million in 2016 and $61 million in 2015, primarily due to the implementation of rates for certain Kemper IGCC in-service assets effective in September 2015 and an annual ECO rate increase of $22 million collected from September through December 2016.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview" and "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" for additional information. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales 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. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel and emissions portion of wholesale revenues from energy sold to customers outside the Company's service territory. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from power sales to non-affiliated utilities, including FERC-regulated MRA sales as well as market-based sales, were as follows:

	2016	2015	2014
		(in millions)	
Capacity and other	**$ 157**	$ 158	$ 160
Energy	**104**	112	163
Total non-affiliated	**$ 261**	$ 270	$ 323

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 electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. In addition, the Company provides service under 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 19.8% of the Company's total operating revenues in 2016 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Wholesale revenues from sales to non-affiliates decreased $9 million, or 3.3%, in 2016 compared to 2015 primarily as a result of an $8 million decrease in energy revenues, of which $10 million was associated with lower fuel prices, offset by an increase in KWH sales of $2 million. Wholesale revenues from sales to non-affiliates decreased $53 million, or 16.4%, in 2015 compared to 2014 primarily as a result of a $51 million decrease in energy revenues, of which $13 million was associated with a decrease in KWH sales and $38 million was associated with lower fuel prices.

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 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 decreased $50 million, or 65.8%, in 2016 compared to 2015 primarily due to a $50 million decrease in energy revenues of which $4 million was associated with lower fuel prices and $46 million was associated with a decrease in KWH sales as a result of lower cost generation available in the Southern Company system. Wholesale revenues from sales to affiliates decreased $31 million, or 29.0%, in 2015 compared to 2014 primarily due to a $31 million decrease in energy revenues of which $28 million was associated with lower fuel prices and $3 million was associated with a decrease in KWH sales.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2016 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2016	**2016**	2015	**2016(*)**	2015(*)
	(in millions)				
Residential	**2,051**	**1.3 %**	(4.8)%	**(2.4)%**	(0.4)%
Commercial	**2,842**	**1.3**	(1.9)	**(2.2)**	(0.4)
Industrial	**4,906**	**(1.0)**	0.3	**(1.6)**	0.8
Other	**39**	**(1.3)**	(2.1)	**(1.3)**	(2.1)
Total retail	**9,838**	**0.1**	(1.4)	**(1.9)%**	0.2 %
Wholesale					
Non-affiliated	**3,920**	**1.7**	(8.1)		
Affiliated	**1,108**	**(60.5)**	(3.2)		
Total wholesale	**5,028**	**(24.5)**	(6.1)		
Total energy sales	**14,866**	**(9.8)%**	(3.4)%		

(*) In the first quarter 2015, the Company updated the methodology to estimate the unbilled revenue allocation among customer classes. This change did not have a material impact on net income. The KWH sales variances in the above table reflect an adjustment to the estimated allocation of the Company's unbilled 2014 and first quarter 2015 KWH sales among customer classes that is consistent with the actual allocation in 2015 and 2016, respectively. Without this adjustment, 2016 weather-adjusted residential sales decreased 1.0%, commercial sales decreased 0.6%, and industrial KWH sales decreased 1.0% as compared to the corresponding period in 2015. Without this adjustment, 2015 weather-adjusted residential sales decreased 1.8%, commercial sales decreased 2.1%, and industrial KWH sales increased 0.3% as compared to the corresponding period in 2014.

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales increased 0.1% in 2016 as compared to the prior year. This increase was primarily the result of warmer weather in the third quarter 2016 as compared to the corresponding period in 2015. Weather-adjusted residential and commercial KWH sales decreased primarily due to decreased customer usage partially offset by customer growth. The decrease in industrial KWH energy sales was primarily due to planned and unplanned outages by large industrial customers.

Retail energy sales decreased 1.4% in 2015 as compared to the prior year. This decrease was primarily the result of milder weather in the first and fourth quarters of 2015 as compared to the corresponding periods in 2014. Weather-adjusted residential and commercial KWH sales decreased primarily due to decreased customer usage partially offset by customer growth. Household income, one of the primary drivers of residential customer usage, had modest growth in 2015. The increase in industrial KWH energy sales was primarily due to expanded operation by many industrial customers.

Wholesale energy sales to non-affiliates decreased in 2016 compared to 2015 primarily due to lower fuel prices which was partially offset by an increased opportunity sales to the external market based on higher demand. Wholesale energy sales to non-affiliates decreased in 2015 compared to 2014 primarily due to decreased opportunity sales to the external market based on lower demand which was offset by lower fuel prices.

Wholesale energy 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 electric service territory, and the availability of the Southern Company system's generation.

Wholesale energy sales to affiliates decreased in 2016 compared to 2015 primarily due to lower fuel cost and reduced sales to affiliate companies. Wholesale energy sales to affiliates decreased in 2015 compared to 2014 primarily due to lower fuel cost and reduced sales to affiliate companies.

Fuel and Purchased Power Expenses

Fuel costs constitute one of the single largest expenses 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:

	2016	2015	2014
Total generation *(in millions of KWHs)*	**14,514**	17,014	16,881
Total purchased power *(in millions of KWHs)*	**1,574**	539	886
Sources of generation *(percent)* –			
Coal	**9**	17	42
Gas	**91**	83	58
Cost of fuel, generated *(in cents per net KWH)* –			
Coal	**3.91**	3.71	3.96
Gas	**2.41**	2.58	3.37
Average cost of fuel, generated *(in cents per net KWH)*	**2.55**	2.78	3.64
Average cost of purchased power *(in cents per net KWH)*	**3.07**	2.17	4.85

Fuel and purchased power expenses were $377 million in 2016, a decrease of $78 million, or 17.1%, as compared to the prior year. The decrease was primarily due to a $20 million decrease in the cost of natural gas and a decrease of $82 million due to a decrease in the volume of KWH generation, partially offset by a $12 million increase in KWHs purchased and a $12 million increase in the cost of coal. Fuel and purchased power expenses were $455 million in 2015, a decrease of $162 million, or 26.3%, as compared to the prior year. The decrease was primarily due to a $125 million decrease in the cost of fuel and purchased power and a decrease of $183 million in the volume of KWHs generated by coal and purchased, partially offset by a $146 million increase in the volume of KWHs generated by gas.

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 clauses. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein and Note 1 to the financial statements under "Fuel Costs" for additional information.

Fuel

Fuel expense decreased $100 million, or 22.6%, in 2016 compared to 2015 due to an 8.2% decrease in the average cost of fuel per KWH generated and a 15.5% decrease in the volume of KWHs generated. Fuel expense decreased $131 million, or 22.8%, in

2015 compared to 2014. The decrease was the result of a 23.6% decrease in the average cost of fuel per KWH generated, partially offset by a 0.9% increase in the volume of KWHs generated.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was flat in 2016 compared to 2015. Purchased power expense from non-affiliates decreased $13 million, or 72.2%, in 2015 compared to 2014. The decrease was primarily the result of a 72.4% decrease in the average cost per KWH purchased.

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

Purchased Power - Affiliates

Purchased power expense from affiliates increased $22 million, or 314.3%, in 2016 compared to 2015. The increase in 2016 was primarily the result of a 338.4% increase in the volume of KWHs purchased due to the availability of lower cost energy as compared to the cost of self-generation and a slight increase in the average cost per KWH purchased compared to 2015. Purchased power expense from affiliates decreased $18 million, or 72.0%, in 2015 compared to 2014. The decrease in 2015 was primarily the result of a 58.3% decrease in the volume of KWHs purchased and a 36.9% decrease in the average cost per KWH purchased compared to 2014.

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 or other contractual agreements, as approved by the FERC.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses increased $38 million, or 13.9%, in 2016 compared to the prior year. The increase was primarily due to a $28 million increase in operations and maintenance expenses related to the combined cycle and the associated common facilities portion of the Kemper IGCC, $10 million in amortization of prior operations and maintenance expense deferrals that the Company began recognizing in connection with rates associated with the Kemper IGCC in-service assets, and a $7 million increase in transmission and distribution expenses primarily related to overhead line maintenance and vegetation management, partially offset by a $9 million decrease in generation outage costs.

Other operations and maintenance expenses increased $3 million, or 1.1%, in 2015 compared to the prior year. The increase was primarily related to a $7 million increase in employee compensation and benefits, including pension costs, and a $6 million increase in generation maintenance expenses related to the combined cycle and the associated common facilities portion of the Kemper IGCC. See Note 2 to the financial statements for additional information on pension costs. Beginning in the third quarter 2015, in connection with the implementation of rates associated with the Kemper IGCC, the Company began expensing certain ongoing project costs associated with Kemper IGCC assets placed in service that previously were deferred as regulatory assets. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Rate Case" and " – Regulatory Assets and Liabilities" herein for additional information. These increases in 2015 were partially offset by decreases of $4 million in transmission and distribution expenses primarily related to overhead line maintenance and vegetation management, $3 million in generation maintenance expenses primarily due to lower outage costs, and $2 million in overtime labor.

Depreciation and Amortization

Depreciation and amortization increased $9 million, or 7.3%, in 2016 compared to 2015 primarily due to $32 million of additional regulatory asset amortization related to the In-Service Asset Rate Order, ECO plan, and Mercury and Air Toxics Standards (MATS) rule compliance, $13 million associated with Kemper IGCC deferrals primarily related to depreciation deferrals in 2015, and $9 million of depreciation for additional plant in service assets primarily associated with the Plant Daniel scrubbers. These increases were partially offset by $23 million of amortization of regulatory deferrals related to the In-Service Asset Rate Order and a $22 million deferral associated with the implementation of revised ECO plan rates with the first billing cycle for September 2016.

Depreciation and amortization increased $26 million, or 26.8%, in 2015 compared to 2014 primarily due to an $18 million increase in depreciation related to an increase in assets in service and an increase in the depreciation rates, a $16 million increase due to amortization of regulatory assets associated with the Kemper IGCC, and a $2 million increase resulting from the estimated 2015 cost of capital as agreed in the In-Service Asset Rate Order. These increases were partially offset by decreases of $5 million in ECO plan amortization, $3 million in Kemper IGCC combined cycle cost deferrals, and $2 million in deferrals associated with the purchase of Plant Daniel Units 3 and 4. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein for additional information.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "FERC Matters," "Retail Regulatory Matters – Environmental Compliance Overview Plan," and "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $15 million, or 16.0%, in 2016 compared to 2015 primarily due to increases in ad valorem taxes of $10 million, related to an increase in the assessed value of property, as well as increases in franchise taxes of $5 million, related to increased operating revenue. Taxes other than income taxes increased $15 million, or 19.0%, in 2015 compared to 2014 primarily as a result of a $12 million increase in ad valorem taxes and a $4 million increase in franchise taxes, partially offset by a $1 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 $428 million, $365 million, and $868 million were recorded in 2016, 2015, and 2014, 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 Initial DOE Grants and excluding the Cost Cap Exceptions. The 2016 loss also reflects $80 million associated with the estimated minimum probable amount of costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

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

Allowance for Equity Funds Used During Construction

AFUDC equity increased $14 million, or 12.7%, in 2016 as compared to 2015. The increase in 2016 was primarily due to a higher AFUDC rate and an increase in Kemper IGCC CWIP subject to AFUDC, partially offset by placing the Plant Daniel scrubbers in service in November 2015. AFUDC equity decreased $26 million, or 19.1%, in 2015 as compared to 2014. The decrease in 2015 was primarily due to a reduction in the AFUDC rate driven by an increase in short-term borrowings and placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Allowance for Funds Used During Construction" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $67 million in 2016 compared to 2015. The increase was primarily due to an increase of $31 million of interest on deposits resulting from the 2015 reversal of interest associated with the termination of an asset purchase agreement between the Company and SMEPA in May 2015; a $20 million increase due to additional long-term debt and a $30 million decrease in amounts capitalized primarily resulting from $17 million of capitalized interest and the amortization of $13 million in interest deferrals in accordance with the In-Service Asset Rate Order. These net increases were partially offset by a decrease of $16 million in interest accrued on the Mirror CWIP liability prior to refund in 2015.

Interest expense, net of amounts capitalized decreased $38 million, or 84.4%, in 2015 compared to 2014. The decrease was primarily due to a $58 million decrease related to the termination of an asset purchase agreement between the Company and SMEPA in May 2015 which required the return of SMEPA's deposits at a lower rate of interest than accrued, a $5 million decrease associated with amended tax returns, and a $2 million decrease associated with the redemption of long-term debt in 2015. These decreases were partially offset by increases in interest expense of $10 million associated with additional issuances of debt in 2015, $9 million associated with unrecognized tax benefits, and $5 million related to the Mirror CWIP refund, partially offset by a $3 million decrease in AFUDC debt. See Note 5 to the financial statements for additional information.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" for more information.

Income Taxes (Benefit)

Income tax benefits increased $32 million, or 44.4%, in 2016 compared to 2015 primarily as a result of an increase in the estimated probable losses on the Kemper IGCC and an increase in AFUDC equity, which is non-taxable.

Income tax benefits decreased $213 million, or 74.7%, in 2015 compared to 2014 primarily resulting from the reduction in pre-tax losses related to the estimated probable losses on the Kemper IGCC.

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 electric service to retail customers within its traditional service territory 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 – Utility Regulation" herein, and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to recover its prudently-incurred costs, including those related to the remainder of the Kemper IGCC costs not included in current rates, in a timely manner during a time of increasing costs, its ability to prevail against legal challenges associated with the Kemper IGCC, and the completion and subsequent operation of the Kemper IGCC in accordance with any operational parameters that may be adopted by the Mississippi PSC. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies and increasing volumes of electronic commerce transactions. Earnings are subject to a variety of other factors. These factors include weather, competition, developing new and maintaining existing energy contracts and associated load requirements with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources 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. Demand for electricity is primarily driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, which may impact future earnings. Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the Company's financial statements.

The Company provides service under 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 19.8% of the Company's total operating revenues in 2016 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

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 or through long-term wholesale agreements. 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, as compliance plans are revised or updated, and as legal challenges to rules are completed. 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.

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; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection 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 2016, the Company had invested approximately $634 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $17 million, $94 million, and $118 million for 2016, 2015, and 2014, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $127 million from 2017 through 2021, with annual totals of approximately $11 million, $5 million, $24 million, $29 million, and $58 million for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" 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, including the environmental regulations described below; the time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the Company's fuel mix; and environmental remediation requirements. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "Retail Regulatory Matters – Environmental Compliance Overview Plan" herein for additional information.

Compliance with any new federal or state legislation or regulations relating to air, water, and land resources 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.

In 2012, the EPA finalized the MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. The implementation strategy for the MATS rule included emission controls, retirements, and fuel conversions at affected units. All of the Company's units that are subject to the MATS rule completed the measures necessary to achieve compliance with this rule or were retired prior to or during 2016.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a revised eight-hour ozone NAAQS and published its final area designations in 2012. All areas within the Company's service territory have achieved attainment of the 2008 standard. In October 2015, the EPA published a more stringent eight-hour ozone NAAQS. This new standard could potentially require additional emission controls, improvements in control efficiency, and operational fuel changes and could affect the siting of new generating facilities. States were required to recommend area designations by October 2016, and no areas within the Company's service territory were proposed for designation as nonattainment.

The EPA regulates fine particulate matter concentrations through an annual and 24-hour average NAAQS, based on standards promulgated in 1997, 2006, and 2012. All areas in which the Company's generating units are located have been determined by the EPA to be in attainment with those standards.

In 2010, the EPA revised the NAAQS for sulfur dioxide (SO_2), establishing a new one-hour standard. No areas within the Company's service territory have been designated as nonattainment under this standard. However, in 2015, the EPA finalized a data requirements rule to support final EPA designation decisions for all remaining areas under the SO_2 standard, which could result in nonattainment designations for areas within the Company's service territory. Nonattainment designations could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide (NO_x) emissions from power plants in two phases – Phase 1 in 2015 and Phase 2 in 2017. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone season NO_x program, beginning in 2017, and establishes more stringent ozone-season emissions budgets in Alabama and Mississippi. The State of Alabama is also in the CSAPR annual SO_2 and NO_x programs.

The EPA finalized regional haze regulations 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, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. On December 14, 2016, the EPA finalized revisions to the regional haze regulations. These regulations establish a deadline of July 31, 2021 for states to submit revised SIPs to the EPA demonstrating reasonable progress toward the statutory goal of achieving natural background conditions by 2064. State implementation of the reasonable progress requirements defined in this final rule could require further reductions in SO_2 or NO_x emissions.

In June 2015, the EPA published a final rule requiring certain states (including Alabama and Mississippi) to revise or remove 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), and many states have submitted proposed SIP revisions in response to the rule.

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. These regulations could result in significant additional capital expenditures and 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 or through PPAs. The ultimate impact of the eight-hour ozone and SO_2 NAAQS, CSAPR, regional haze regulations, and SSM rule will depend on various factors, such as implementation, adoption, or other action at the state level, and the outcome of pending and/or future legal challenges, and cannot be determined at this time.

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

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective in 2014. The effect of this final rule will depend on the results of additional studies that are currently underway and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System (NPDES) permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule.

In November 2015, the EPA published a final effluent guidelines rule which imposes stringent technology-based requirements for certain wastestreams from steam electric power plants. The revised technology-based limits and compliance dates will be incorporated into future renewals of NPDES permits at affected units and may require the installation and operation of multiple technologies sufficient to ensure compliance with applicable new numeric wastewater compliance limits. Compliance deadlines between November 1, 2018 and December 31, 2023 will be established in permits based on information provided for each applicable wastestream.

In 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs. The final rule significantly expands the scope of federal jurisdiction under the CWA and could have significant impacts on economic development projects which could affect customer demand growth. In addition, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines. The rule became effective in August 2015 but, in October 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The case is held in abeyance pending review by the U.S. Supreme Court of challenges to the U.S. Court of Appeals for the Sixth Circuit's jurisdiction in the case.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and decisions on infrastructure expansion and improvements. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate impact of these final rules will depend on various factors, such as pending and/or future legal challenges, compliance dates, and implementation of the rules, and cannot be determined at this time.

Coal Combustion Residuals

The Company currently manages two electric generating plants in Mississippi and is also part owner of a plant located in Alabama, each with onsite CCR storage units consisting of landfills and surface impoundments (CCR Units). In addition to on-site storage, the Company also sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Mississippi and Alabama each have their own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

The CCR Rule became effective in October 2015. The CCR Rule regulates the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not automatically require closure of CCR Units but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the required closure of a CCR Unit. On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation Act (WIIN Act). The WIIN Act allows states to establish permit programs for implementing the CCR Rule, if the EPA approves the program, and allows for federal permits and EPA enforcement where a state permitting program does not exist.

Based on current cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, the Company has recorded AROs related to the CCR Rule. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, the Company expects to continue to periodically update these estimates. The Company has posted closure and post-closure care plans to its public website as required by the CCR Rule; however, the ultimate impact of the CCR Rule will depend on the results of initial and ongoing minimum criteria assessments and the implementation of state or federal permit programs. On December 15, 2016, the Mississippi PSC granted a CPCN to the Company authorizing certain projects associated with complying with the CCR Rule. Additionally in this order, the Mississippi PSC also authorized the Company to recover any costs associated with the CPCN, including future monitoring costs, through the ECO plan rate. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information regarding the Company's AROs as of December 31, 2016.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up affected sites. 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. 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

In October 2015, the EPA published two final actions that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final actions contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final action, known as the Clean Power Plan, establishes guidelines for states to develop plans to meet EPA-mandated CO_2 emission rates or emission reduction goals for existing units. The EPA's final guidelines require state plans to meet interim CO_2 performance rates between 2022 and 2029 and final rates in 2030 and thereafter. At the same time, the EPA published a proposed federal plan and model rule that, when finalized, states can adopt or that would be put in place if a state either does not submit a state plan or its plan is not approved by the EPA. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for review with the courts. The stay will remain in effect through the resolution of the litigation, including any review by the U.S. Supreme Court.

These guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions and decisions on infrastructure expansion and improvements. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs. However, the ultimate financial and operational impact of the final rules on the Company cannot be determined at this time and will depend upon numerous factors, including the outcome of pending legal challenges, including legal challenges filed by the traditional electric operating companies, and any individual state implementation of the EPA's final guidelines in the event the rule is upheld and implemented.

In December 2015, parties to the United Nations Framework Convention on Climate Change – including the United States – adopted the Paris Agreement, which establishes a non-binding universal framework for addressing greenhouse gas emissions based on nationally determined contributions. It also sets in place a process for tracking progress toward the goals every five years. The ultimate impact of this agreement depends on its implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2015 greenhouse gas emissions were approximately 7 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2016 greenhouse gas emissions on the same basis is approximately 7 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

FERC Matters

Municipal and Rural Associations Tariff

In 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.

In 2014, the Company reached, and the FERC accepted, a settlement agreement with its wholesale customers for an estimated annual increase in the MRA cost-based tariff of approximately $10 million, effective May 1, 2014. Included in this settlement agreement was a mechanism allowing the Company to adjust the wholesale revenue requirement in a subsequent rate proceeding in the event the Kemper IGCC, or any substantial portion thereof, was placed in service before or after December 1, 2014. Therefore, the Company recorded a regulatory asset as a result of a portion of the Kemper IGCC being placed in service prior to the projected date, which was fully amortized as of December 31, 2015. In May 2015, the FERC accepted a further settlement agreement between the Company and its wholesale customers to forgo a MRA cost-based electric tariff increase by, among other things, increasing the accrual of AFUDC and lowering the portion of CWIP in rate base, effective April 1, 2015, resulting in an estimated annual AFUDC increase of approximately $14 million, of which approximately $11 million is related to the Kemper IGCC.

On March 31, 2016, the Company reached a settlement agreement with its wholesale customers, which was subsequently approved by the FERC, for an increase in wholesale base revenues under the MRA cost-based electric tariff, primarily as a result of placing scrubbers for Plant Daniel Units 1 and 2 in service in November 2015. The settlement agreement became effective for services rendered beginning May 1, 2016, resulting in an estimated annual revenue increase of $7 million under the MRA cost-based electric tariff. Additionally, under the settlement agreement, the tariff customers agreed to similar regulatory treatment for MRA tariff ratemaking as the treatment approved for retail ratemaking under the In-Service Asset Rate Order. This regulatory treatment primarily includes (i) recovery of the Kemper IGCC assets currently operational and providing service to customers and other related costs, (ii) amortization of the Kemper IGCC-related regulatory assets included in rates under the settlement agreement over the 36 months ending April 30, 2019, (iii) Kemper IGCC-related expenses included in rates under the settlement agreement no longer being deferred and charged to expense, and (iv) removing all of the Kemper IGCC CWIP from rate base with a corresponding increase in accrual of AFUDC. The additional resulting AFUDC is estimated to be approximately $14 million through the Kemper IGCC's projected in-service date of mid-March 2017.

Fuel Cost Recovery

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective with the first billing cycle for September 2016, fuel rates decreased $11 million annually for wholesale MRA customers and $1 million annually for wholesale MB customers. At December 31, 2016 and 2015, the amount of over recovered wholesale MRA fuel costs were approximately $13 million and $24 million, respectively, which is included in over recovered regulatory clause liabilities, current in the balance sheets. Effective January 1, 2017, the wholesale MRA fuel rate increased $10 million annually.

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 should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Market-Based Rate Authority

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

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

Retail Regulatory Matters

General

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased power, energy efficiency programs, ad valorem taxes, property damage, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In 2013, the 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.

Renewables

In November 2015, the Mississippi PSC issued orders approving three solar facilities for a combined total of approximately 105 MWs. The Company will purchase all of the energy produced by the solar facilities for the 25-year term under each of the three PPAs. The projects are expected to be in service by the second quarter 2017 and the resulting energy purchases are expected to be recovered through the Company's fuel cost recovery mechanism. The Company may retire the renewable energy credits (REC) generated on behalf of its customers or sell the RECs, separately or bundled with energy, to third parties.

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 a projected revenue requirement, and the PEP lookback filing, which is filed after the end of the year and allows for review of the 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 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. In 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $5 million. Unresolved matters related to the 2010 PEP lookback filing, which remain under review, also impact the 2012 PEP lookback filing.

In 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9%, or $15 million, annually, effective March 19, 2013. The Company may be entitled to $3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

In 2014, 2015, and 2016, the Company submitted its annual PEP lookback filings for the prior years, which for 2013 and 2014 each indicated no surcharge or refund and for 2015 indicated a $5 million surcharge. On July 12, 2016 and November 15, 2016, the Company submitted its annual projected PEP filings for 2016 and 2017, respectively, which each indicated no change in rates. The Mississippi PSC suspended each of these filings to allow more time for review.

In 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.

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

Energy Efficiency

In 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.

On May 3, 2016, the Mississippi PSC issued an order approving the Company's Energy Efficiency Cost Rider Compliance filing, which reduced annual retail revenues by approximately $2 million effective with the first billing cycle for June 2016.

On November 30, 2016, the Company submitted its Energy Efficiency Cost Rider Compliance filing, which included an increase of $1 million in annual retail revenues. The ultimate outcome of this matter cannot be determined at this time.

See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Environmental Compliance Overview Plan

In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in November 2015. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. In 2014, the Company entered into a settlement agreement with the Sierra Club that, among other things, required the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges to the issuance of the CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which also occurred in 2014. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018 (and the units were retired in July 2016). The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015 (which occurred in April 2015) and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) no later than April 2016 (which occurred in February and March 2016, respectively) and begin operating those units solely on natural gas (which occurred in June and July 2016, respectively).

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. As of December 31, 2016, $17 million of Plant Greene County costs have been reclassified as regulatory assets and are expected to be recovered through the ECO plan and other existing cost recovery mechanisms over a period to be determined by the Mississippi PSC. The Mississippi PSC approved $41 million of costs that were reclassified to a regulatory asset associated with Plant Watson for amortization over a five-year period that began in July 2016. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

On August 17, 2016, the Mississippi PSC approved the Company's revised ECO plan filing for 2016, which requested the maximum 2% annual increase in revenues, approximately $18 million, primarily related to the Plant Daniel Units 1 and 2 scrubbers being placed in service in November 2015. The revised rates became effective with the first billing cycle for September 2016. Approximately $22 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2017 filing.

On February 14, 2017, the Company submitted its ECO plan filing for 2017, which requested an increase in annual revenues over 2016, capped at 2% of total retail revenues, of approximately $18 million, primarily related to the Plant Daniel Units 1 and 2 scrubbers placed in service in November 2015. The revenue requirement in excess of the 2%, approximately $27 million plus carrying costs, will be carried forward to the 2018 filing. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually. The Mississippi PSC approved the 2016 retail fuel cost recovery factor, effective January 5, 2016, which resulted in an annual revenue decrease of approximately $120 million. On August 17, 2016, the Mississippi PSC approved an additional decrease of $51 million annually in fuel cost recovery rates effective with the first billing cycle for September 2016. At December 31, 2016 and 2015, over recovered retail fuel costs were approximately $37 million and $71 million, respectively, which is included in over recovered regulatory clause liabilities, current in the balance sheets. On January 12, 2017, the Mississippi PSC approved the 2017 retail fuel cost recovery factor, effective February 2017 through January 2018, which will result in an annual revenue increase of approximately $55 million.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

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 17, 2016, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2016, which included an annual rate decrease of 0.07%, or $1 million in annual retail revenues, primarily due to the prior year over recovery.

System Restoration Rider

In October 2015, the Mississippi PSC approved the Company's 2015 SRR rate filing, which proposed that the SRR rate remain level at zero and the Company continue to accrue $3 million annually to the property damage reserve.

On February 1, 2016, the Company submitted its 2016 SRR rate filing which proposed no changes to either the SRR rate or the annual property damage reserve accrual. On February 19, 2016, the filing was suspended by the Mississippi PSC for review. The ultimate outcome of this matter cannot be determined at this time.

On February 3, 2017, the Company submitted its 2017 SRR rate filing, which proposed that the rate level remain at zero and the Company be allowed to accrue $4 million annually to the property damage reserve in 2017. The ultimate outcome of this matter cannot be determined at this time.

See Note 1 to the financial statements under "Provision for Property Damage" for additional information.

Storm Damage Cost Recovery

In connection with the damage associated with Hurricane Katrina, the Mississippi PSC authorized the issuance of system restoration bonds in 2006. In accordance with a Mississippi PSC order dated January 24, 2017, the Company has adjusted the System Restoration Charge implemented after Hurricane Katrina to zero. Upon completion of the proper defeasance process by the Mississippi State Bond Commission, the Company's obligations in relation to system restoration bonds issued after Hurricane Katrina in 2005 will be completely satisfied.

Provision for Property Damage

On January 21, 2017, a tornado caused extensive damage to the Company's transmission and distribution infrastructure. Preliminary storm damage repairs have been estimated at $11 million. A portion of these costs may be charged to the retail property damage reserve and addressed in a subsequent SRR rate filing. The ultimate outcome of this matter cannot be determined at this time.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

The Kemper IGCC utilizes IGCC technology with an expected output capacity of 582 MWs. The Kemper IGCC is 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 in 2013. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion, net of $245 million of Initial 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. The Kemper IGCC was originally projected to be placed in service in May 2014. The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." The Company achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. The Company subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced and captured CO_2, and has produced sulfuric acid and ammonia, all of acceptable quality under the related off-take agreements. On February 20, 2017, the Company determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, the Company currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.

The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision discussed herein under "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order"), and actual costs incurred as of December 31, 2016, all of which include 100% of the costs for the Kemper IGCC, are as follows:

Cost Category	2010 Project Estimate[(a)]	Current Cost Estimate[(b)]	**Actual Costs**
		(in billions)	
Plant Subject to Cost Cap[(c)(e)]	$ 2.40	$ 5.64	**$ 5.44**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC[(d)]	0.17	0.79	**0.75**
Combined Cycle and Related Assets Placed in Service – Incremental[(e)]	—	0.04	**0.04**
General Exceptions	0.05	0.10	**0.09**
Deferred Costs[(e)]	—	0.22	**0.21**
Additional DOE Grants	—	(0.14)	**(0.14)**
Total Kemper IGCC[(f)]	$ 2.97	$ 6.99	**$ 6.73**

(a) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities approved in 2011 by the Mississippi PSC, as well as the lignite mine and equipment, AFUDC, and general exceptions.

(b) Amounts in the Current Cost Estimate include certain estimated post-in-service costs which are expected to be subject to the cost cap.

(c) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Current Cost Estimate and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014 that are subject to the $2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information.

(d) The Company's 2010 Project Estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC as described in "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order." The Current Cost Estimate also reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction. See "FERC Matters" herein for additional information.

(e) Non-capital Kemper IGCC-related costs incurred during construction were initially deferred as regulatory assets. Some of these costs are now included in rates and are being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2016. The wholesale portion of debt carrying costs, whether deferred or recognized through income, is not included in the Current Cost Estimate and the Actual Costs at December 31, 2016. See "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein for additional information.

(f) The Current Cost Estimate and the Actual Costs include $2.76 billion that will not be recovered for costs above the cost cap, $0.83 billion of investment costs included in current rates for the combined cycle and related assets in service, and $0.08 billion of costs that were previously expensed for the combined cycle and related assets in service. The Current Cost Estimate and the Actual Costs exclude $0.25 billion of costs not included in current rates for post-June 2013 mine operations, the lignite fuel inventory, and the nitrogen plant capital lease, which will be included in the 2017 Rate Case to be filed by June 3, 2017. See Note 1 to the financial statements under "Fuel Inventory," Note 6 to the financial statements under "Capital Leases," and "Rate Recovery of Kemper IGCC Costs – 2017 Rate Case" herein for additional information.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2016, $3.67 billion was included in property, plant, and equipment (which is net of the Initial DOE Grants, the Additional DOE Grants, and estimated probable losses of $2.84 billion), $6 million in other property and investments, $75 million in fossil fuel stock, $47 million in materials and supplies, $29 million in other regulatory assets, current, $172 million in other regulatory assets, deferred, $3 million in other current assets, and $14 million in other deferred charges and assets in the balance sheet.

The Company does not intend to seek rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate of $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016, 2015, and 2014, respectively. Since 2012, in the aggregate, the Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016. The increases to the cost estimate in 2016 primarily reflect $186 million for the extension of the Kemper IGCC's projected in-service date from August 31, 2016 to March 15, 2017 and $162 million for increased efforts related to operational readiness and challenges in start-up and commissioning activities, including the cost of repairs and modifications to both gasifiers, mechanical improvements to coal feed and ash management systems, and outage work, as well as certain post-in-service costs expected to be subject to the cost cap.

In addition to the current construction cost estimate, the Company is identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap.

Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month. For additional information, see "2015 Rate Case" herein.

Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). Any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, cannot now be determined but could result in further material charges that could have a material impact on the Company's results of operations, financial condition, and liquidity.

As of December 31, 2016, in addition to the $2.76 billion of costs above the Mississippi PSC's $2.88 billion cost cap that have been recognized as a charge to income, the Company had incurred approximately $1.99 billion in costs subject to the cost cap and approximately $1.46 billion in Cost Cap Exceptions related to the construction and start-up of the Kemper IGCC that are not included in current rates. These costs primarily relate to the following:

Cost Category		**Actual Costs**
		(in billions)
Gasifiers and Gas Clean-up Facilities	$	1.88
Lignite Mine Facility		0.31
CO_2 Pipeline Facilities		0.11
Combined Cycle and Common Facilities		0.16
AFUDC		0.69
General exceptions		0.07
Plant inventory		0.03
Lignite inventory		0.08
Regulatory and other deferred assets		0.12
Subtotal	$	3.45
Additional DOE Grants		(0.14)
Total	**$**	**3.31**

Of these amounts, approximately 29% is related to wholesale and approximately 71% is related to retail, including the 15% portion that was previously contracted to be sold to SMEPA. The Company and its wholesale customers have generally agreed to the similar regulatory treatment for wholesale tariff purposes as approved by the Mississippi PSC for retail for Kemper IGCC-related costs. See "FERC Matters – Municipal and Rural Associations Tariff" and "Termination of Proposed Sale of Undivided Interest" herein for further information.

Prudence

On August 17, 2016, the Mississippi PSC issued an order establishing a discovery docket to manage all filings related to the prudence of the Kemper IGCC. On October 3, 2016, the Company made a required compliance filing, which included a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate. On November 17, 2016, the Company submitted a supplemental filing to the October 3, 2016 compliance filing to present revised non-fuel operations and maintenance expense projections for the first year after the Kemper IGCC is placed in service. This supplemental filing included approximately $68 million in additional estimated operations and maintenance costs expected to be required to support the operations of the Kemper IGCC during that period. The Company will not seek recovery of the $68 million in additional estimated costs from customers if incurred.

The Company expects the Mississippi PSC to address these matters in connection with the 2017 Rate Case.

Economic Viability Analysis

In the fourth quarter 2016, as a part of its Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected.

As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings discussed above, on February 21, 2017, the Company filed an updated project economic viability analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order confirming authorization of the Kemper IGCC. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

The Company expects the Mississippi PSC to address this matter in connection with the 2017 Rate Case.

2017 Accounting Order Request

After the remainder of the plant is placed in service, AFUDC equity of approximately $11 million per month will no longer be recorded in income, and the Company expects to incur approximately $25 million per month in depreciation, taxes, operations and maintenance expenses, interest expense, and regulatory costs in excess of current rates. The Company expects to file a request for authority from the Mississippi PSC and the FERC to defer all Kemper IGCC costs incurred after the in-service date that cannot be capitalized, are not included in current rates, and are not required to be charged against earnings as a result of the $2.88 billion cost cap until such time as the Mississippi PSC completes its review and includes the resulting allowable costs in rates. In the event that the Mississippi PSC does not grant the Company's request, these monthly expenses will be charged to income as incurred and will not be recoverable through rates.

2017 Rate Case

The Company continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. The Company also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein and under "Prudence," "Lignite Mine and CO_2 Pipeline Facilities," "Termination of Proposed Sale of Undivided Interest," and "Income Tax Matters," these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

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 in 2013. The Company expects to utilize this legislation to securitize prudently-incurred qualifying facility costs in excess of the certificated cost estimate of $2.4 billion. Qualifying facility costs include, but are not limited to, pre-construction costs, construction costs, regulatory costs, and accrued AFUDC. The Court's decision regarding the 2013 MPSC Rate Order did not impact the Company's ability to utilize alternate financing through securitization or the February 2013 legislation.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, the Company is developing both a traditional rate case requesting full cost recovery of the amounts not currently in rates and a rate mitigation plan that together represent the Company's probable filing strategy. The Company also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both the Company and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on the Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, the Company intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

The Company has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

2015 Rate Case

On August 13, 2015, the Mississippi PSC approved the Company's request for interim rates, which presented an alternative rate proposal (In-Service Asset Proposal) designed to recover the Company's costs associated with the Kemper IGCC assets that are commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs. The interim rates were designed to collect approximately $159 million annually and became effective in September 2015, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued the In-Service Asset Rate Order adopting in full the 2015 Stipulation entered into between the Company and the MPUS regarding the In-Service Asset Proposal. The In-Service Asset Rate Order provided for retail rate recovery of an annual revenue requirement of approximately $126 million, based on the Company's actual average capital structure, with a maximum common equity percentage of 49.733%, a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excluded the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA but reserved the Company's right to seek recovery in a future proceeding. See "Termination of Proposed Sale of Undivided Interest" herein for additional information. The Company is required to file the 2017 Rate Case by June 3, 2017.

With implementation of the new rates on December 17, 2015, the interim rates were terminated and, in March 2016, the Company completed customer refunds of approximately $11 million for the difference between the interim rates collected and the permanent rates.

2013 MPSC Rate Order

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 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. In March 2013, the Mississippi PSC issued a 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 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service, based on a mirror CWIP methodology (Mirror CWIP rate).

On February 12, 2015, the Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. On July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015 and required the fourth quarter 2015 refund of the $342 million collected under the 2013 MPSC Rate Order, along with associated carrying costs of $29 million. The Court's decision did not impact the 2012 MPSC CPCN Order or the February 2013 legislation described above.

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. Through December 31, 2016, AFUDC recorded since the original May 2014 estimated in-service date for the Kemper IGCC has totaled $398 million, which will continue to accrue at approximately $16 million per month until the remainder of the plant is placed in service. The Company has not recorded any AFUDC on Kemper IGCC costs in excess of the $2.88 billion cost cap, except for Cost Cap Exception amounts.

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 including availability factor, heat rate, lignite heat content, and chemical revenue based upon assumptions in the Company's petition for the CPCN. The Company expects the Mississippi PSC to apply operational parameters in connection with the 2017 Rate Case and future proceedings related to the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or the Company incurs additional costs to satisfy such parameters, there could be a material adverse impact on the Company's financial statements. See "Prudence" herein for additional information.

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset through the in-service date, subject to review of such costs by the Mississippi PSC. Such costs include, but are not limited to, carrying costs on Kemper IGCC assets currently placed in service, costs associated with Mississippi PSC and MPUS consultants, prudence costs, legal fees, and operating expenses associated with assets placed in service.

In August 2014, the Company requested confirmation by the Mississippi PSC of the Company's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. 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. Beginning in the third quarter 2015 and the second quarter 2016, in connection with the implementation of retail and wholesale rates, respectively, the Company began expensing certain ongoing project costs and certain retail debt carrying costs (associated with assets placed in service and other non-CWIP accounts) that previously were deferred as regulatory assets and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees. The amortization periods for these regulatory assets vary from two years to 10 years as set forth in the In-Service Asset Rate Order and the settlement agreement with wholesale customers. As of December 31, 2016, the balance associated with these regulatory assets was $97 million, of which $29 million is included in current assets. Other regulatory assets associated with the remainder of the Kemper IGCC totaled $104 million as of December 31, 2016. The amortization period for these assets is expected to be determined by the Mississippi PSC in the 2017 Rate Case. See "FERC Matters" herein for additional information related to the 2016 settlement agreement with wholesale customers.

The In-Service Asset Rate Order requires the Company to submit an annual true-up calculation of its actual cost of capital, compared to the stipulated total cost of capital, with the first occurring as of May 31, 2016. At December 31, 2016, the Company's related regulatory liability included in its balance sheet totaled approximately $7 million. See "2015 Rate Case" herein for additional information.

Also see Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company owns 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 in June 2013.

In 2010, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is operating and managing 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 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.

In addition, the Company has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company entered into agreements with Denbury Onshore (Denbury) and Treetop Midstream Services, LLC (Treetop), pursuant to which Denbury would purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop would purchase 30% of the CO_2 captured from the Kemper IGCC. On June 3, 2016, the Company cancelled its contract with Treetop and amended its contract with Denbury to reflect, among other things, Denbury's agreement to purchase 100% of the CO_2 captured from the Kemper IGCC, an initial contract term of 16 years, and termination rights if the Company has not satisfied its contractual obligation to deliver captured CO_2 by July 1, 2017, in addition to Denbury's existing termination rights in the event of a change in law, force majeure, or an event of default by the Company. Any termination or material modification of the agreement with Denbury could impact the operations of the Kemper IGCC and result in a material reduction in the Company's revenues to the extent the Company is not able to enter into other similar contractual arrangements or otherwise sequester the CO_2 produced. Additionally, sustained oil price reductions could result in significantly lower revenues than the Company originally forecasted to be available to offset customer rate impacts, which could have a material impact on the Company's financial statements.

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

Termination of Proposed Sale of Undivided Interest

In 2010 and as amended in 2012, the Company and SMEPA entered into an agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC (15% Undivided Interest). On May 20, 2015, SMEPA notified the Company of its termination of the agreement. The Company previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, the Company issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures on December 1, 2017.

Litigation

On April 26, 2016, a complaint against the Company was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. On August 12, 2016, Southern Company and the Company removed the case to the U.S. District Court for the Southern District of Mississippi. The plaintiffs filed a request to remand the case back to state court, which was granted on November 17, 2016. The individual plaintiff, John Carlton Dean, alleges that the Company and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that the Company and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper IGCC and that these alleged breaches have unjustly enriched the Company and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper IGCC; ask the Circuit Court to revoke any licenses or certificates authorizing the Company or Southern Company to engage in any business related to the Kemper IGCC in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper IGCC costs from being charged to customers through electric rates. On December 7, 2016, Southern Company and the Company filed motions to dismiss.

On June 9, 2016, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a complaint against the Company, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint relates to the cancelled CO_2 contract with Treetop and alleges fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of the Company, Southern Company, and SCS and seeks compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, the Company, and SCS have moved to compel arbitration pursuant to the terms of the CO_2 contract.

The Company believes these legal challenges have no merit; however, an adverse outcome in these proceedings could have a material impact on the Company's results of operations, financial condition, and liquidity. The Company will vigorously defend itself in these matters, and the ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In 2008, the 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. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.

Income Tax Matters

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

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of bonus depreciation included in the PATH Act is expected to result in approximately $20 million of positive cash flows for the 2016 tax year, which was not all realized in 2016 due to a projected consolidated net operating loss (NOL) for Southern Company. Dependent upon placing the remainder of the Kemper IGCC in service by December 31, 2017, the Company expects approximately $370 million of positive cash flows from bonus depreciation for the 2017 tax year, which may not all be realized in 2017 due to additional NOL projections for the 2017 tax year. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" and Note 5 to the financial statements under "Current and Deferred Income Taxes – Net Operating Loss" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Investment Tax Credits

The 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. These tax credits were dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In addition, 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 was also a requirement of the Phase II credits. As a result of schedule extensions for the Kemper IGCC, the Phase I tax credits were recaptured in 2013 and the Phase II tax credits were recaptured in 2015.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, has reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and has filed amended federal income tax returns for 2008 through 2013 to also include such deductions. The Kemper IGCC is based on first-of-a-kind technology, and Southern Company believes that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, the Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of December 31, 2016. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter 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 occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

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.

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

The SEC is conducting a formal investigation of Southern Company and the Company concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company and the Company believe the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" herein for additional information on the Kemper IGCC estimated construction costs and expected in-service date. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to have a material impact on the Company's financial statements.

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.

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 other 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.

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

During 2016, the Company further revised its cost estimate to complete construction and start-up of the Kemper IGCC to an amount that exceeds the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Company does not intend to seek any rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions.

As a result of revisions to the cost estimate, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC subject to the construction cost cap of $127 million ($78 million after tax) in the fourth quarter 2016, $88 million ($54 million after tax) in the third quarter 2016, $81 million ($50 million after tax) in the second quarter 2016, $53 million ($33 million after tax) in the first quarter 2016, $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, $9 million ($6 million after tax) in the first quarter 2015, $70 million ($43 million after tax) in the fourth quarter 2014, $418 million ($258 million after tax) in the third quarter 2014, $380 million ($235 million after tax) in the first quarter 2014, $40 million ($25 million after tax) in the fourth quarter 2013, $150 million ($93 million after tax) in the third quarter 2013, $450 million ($278 million after tax) in the second quarter 2013, $462 million ($285 million after tax) in the first quarter 2013, and $78 million ($48 million after tax) in the fourth quarter 2012. In the aggregate, the Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016.

The Company's revised cost estimate reflects an expected in-service date of mid-March 2017 and includes certain post-in-service costs which are expected to be subject to the cost cap. The Company has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

In addition to the current construction cost estimate, the Company is also identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap. In subsequent periods, any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the statements of income and these changes could be material.

Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. However, additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month.

The Company continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. The Company also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further under FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs," " – Prudence," " – Lignite Mine and CO_2 Pipeline Facilities," and " – Termination of Proposed Sale of Undivided Interest" and "Income Tax Matters," these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs, net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, the Company is developing both a traditional rate case requesting full cost recovery of the amounts not currently in rates and a rate mitigation plan that together represent the Company's probable filing strategy. The Company also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both the Company and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on the Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, the Company intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

The Company has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

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

Asset Retirement Obligations

AROs are computed as the fair value of the estimated 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. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily relates to facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations 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 cost estimates for AROs related to the disposal of CCR are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals" herein for additional information.

Given the significant judgment involved in estimating AROs, the Company considers the liabilities for AROs to be critical accounting estimates.

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

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 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 pension and other 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. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows 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. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. For 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $4 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $2 million or less change in total annual benefit expense and a $19 million or less change in projected obligations.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

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 6.5%, 5.99%, and 6.91% for the years ended December 31, 2016, 2015, and 2014, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC equity was $124 million, $110 million, and $136 million in 2016, 2015, and 2014, respectively.

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.

Contingent Obligations

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

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 11 to the financial statements for disclosures impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory* (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

In 2014, the FASB issued ASU No. 2014-15, *Presentation of Financial Statements-Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* (ASU 2014-15). ASU 2014-15 defines management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern within one year of the date the financial statements are issued and to provide related footnote disclosures including management's plans that alleviate substantial doubt. ASU 2014-15 became effective for fiscal years ending after December 15, 2016 and the Company has included the disclosures required by ASU 2014-15 in Note 6 to the financial statements under "Going Concern."

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings for all periods presented were negatively affected by revisions to the cost estimate for the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information.

The Company's capital expenditures and debt maturities are expected to materially exceed operating cash flows through 2021. In addition to the Kemper IGCC, projected capital expenditures in that period include investments to maintain existing generation facilities, to add environmental modifications to existing generating units, and to expand and improve transmission and distribution facilities.

As of December 31, 2016, the Company's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. The Company expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, the Company intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, the Company has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, the Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company, consistent with the requirements of ASU 2014-15. See Note 1 to the financial statements under "Recently Issued Accounting Standards" for additional information regarding ASU 2014-15.

The Company's investments in the qualified pension plan increased in value as of December 31, 2016 as compared to December 31, 2015. On December 19, 2016, the Company voluntarily contributed $47 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated during 2017.

Net cash provided from operating activities totaled $229 million for 2016, an increase of $56 million as compared to 2015. The increase in cash provided from operating activities in 2016 was primarily due to repayment in 2015 of ITCs relating to the Kemper IGCC, as well as the 2015 mirror CWIP refund, partially offset by lower income tax benefits related to the Kemper IGCC in 2016 and lower fuel rates in 2016. Net cash provided from operating activities totaled $173 million for 2015, a decrease of $562 million as compared to 2014. The decrease in net cash provided from operating activities was primarily due to lower R&E tax deductions and lower incremental benefit of ITCs relating to the Kemper IGCC reducing income tax refunds, as well as a decrease in the Mirror CWIP regulatory liability due to the Mirror CWIP refund, partially offset by increases in over recovered regulatory clause revenues and customer liability associated with the Mirror CWIP refund.

Net cash used for investing activities in 2016, 2015, and 2014 totaled $697 million, $906 million, and $1.3 billion, respectively. The cash used for investing activities in 2016 was primarily due to gross property additions related to the Kemper IGCC, partially offset by the receipt of Additional DOE Grants. The cash used for investing activities in 2015 and 2014 was primarily due to gross property additions related to the Kemper IGCC and the Plant Daniel scrubber project.

Net cash provided from financing activities totaled $594 million in 2016 primarily due to long-term debt financings and capital contributions from Southern Company, partially offset by a decrease in short-term borrowings and redemptions of long-term debt.

Net cash provided from financing activities totaled $698 million in 2015 primarily due to short-term borrowings, capital contributions from Southern Company, and long-term debt financings, partially offset by redemptions of long-term debt. Net cash provided from financing activities totaled $593 million in 2014 primarily due to capital contributions from Southern Company, long-term debt financings, and the receipts of interest bearing refundable deposits previously pending, partially offset by redemptions of long-term debt.

Significant balance sheet changes as of December 31, 2016 compared to 2015 included an increase in long-term debt of $538 million. A portion of this debt was used to repay securities and notes payable resulting in a $99 million decrease in securities due within one year and a $477 million decrease in notes payable. Additionally, CWIP increased $291 million primarily due to the Kemper IGCC and the required refund of Mirror CWIP collections which reduced the related customer liability by $72 million. Other significant changes include a $383 million increase in accrued income taxes offset by unrecognized tax benefits of $368 million reclassified from long-term to current. Total common stockholder's equity increased $584 million primarily due to the receipt of capital contributions from Southern Company.

The Company's ratio of common equity to total capitalization plus short-term debt was 45.2% and 47.1% at December 31, 2016 and 2015, respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

As discussed above, the Company's financial condition and its ability to obtain funds needed for normal business operations and completion of the construction and start-up of the Kemper IGCC were adversely affected for all periods presented by events relating to the Kemper IGCC. In December 2015, the Mississippi PSC approved the In-Service Asset Rate Order, which among other things, provided for retail rate recovery of an annual revenue requirement of approximately $126 million effective December 17, 2015. The amount, type, and timing of future financings will depend upon regulatory approval, prevailing market conditions, and other factors, which includes resolution of Kemper IGCC cost recovery. See "Capital Requirements and Contractual Obligations" herein and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" herein for additional information.

As of December 31, 2016, the Company's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. The Company expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, the Company intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, the Company has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, the Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company, consistent with the requirements of ASU 2014-15. See Note 1 to the financial statements under "Recently Issued Accounting Standards" for additional information regarding ASU 2014-15.

The Company received $245 million of Initial DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of grants from the DOE is expected to be received for commercial operation of the Kemper IGCC. On April 8, 2016, the Company received approximately $137 million in Additional DOE Grants for the Kemper IGCC, which are expected to be used to reduce future rate impacts for customers. In addition, 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, public offerings of securities are required to be registered with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the FERC are continuously monitored and appropriate filings are made to ensure flexibility in raising capital. Any future financing through secured debt would also require approval by the Mississippi PSC.

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.

At December 31, 2016, the Company had approximately $224 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2016 were as follows:

Expires			Executable Term Loans		Expires Within One Year	
2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)	(in millions)		(in millions)		(in millions)	
$ 173	$ 173	$ 150	$ —	$ 13	$ 13	$ 160

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

Most of these bank credit arrangements, as well as the Company's term loan arrangements, contain covenants that limit debt levels and typically contain cross acceleration or 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 specific threshold. Such cross acceleration provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2016, the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowing.

Subject to applicable market conditions, the Company expects to renew or replace its bank credit arrangements as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

A portion of the $150 million unused credit arrangements with banks is allocated to provide liquidity support to the Company's 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, 2016 was approximately $40 million.

Short-term borrowings are included in notes payable in the balance sheets. The Company had no short-term borrowings in 2014. Details of short-term borrowing for 2015 and 2016 were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2016	$ 23	2.6%	$ 112	2.0%	$ 500
December 31, 2015	$ 500	1.4%	$ 372	1.3%	$ 515

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

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 Loan and Senior Notes

In March 2016, the Company entered into an unsecured term loan agreement with a syndicate of financial institutions for an aggregate amount of $1.2 billion. The Company borrowed $900 million in March 2016 under the term loan agreement and the remaining $300 million in October 2016. The Company used the initial proceeds to repay $900 million in maturing bank loans in March 2016 and the remaining $300 million to repay at maturity the Company's Series 2011A 2.35% Senior Notes due October 15, 2016. This loan matures on April 1, 2018 and bears interest based on one-month LIBOR.

This bank loan has covenants that limit debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes the long-term debt payable to affiliated trusts, other hybrid securities, and securitized debt relating to the contemplated securitization of certain costs of the Kemper IGCC. At December 31, 2016, the Company was in compliance with its debt limit.

In addition, this bank loan contains cross acceleration provisions to other debt (including guarantee obligations) that would be triggered if the Company defaulted on debt above a specified threshold, the payment of which was then accelerated. The Company is currently in compliance with all such covenants.

Parent Company Loans and Equity Contributions

On January 28, 2016, the Company issued a promissory note for up to $275 million to Southern Company, which matures in December 2017, bearing interest based on one-month LIBOR. During 2016, the Company borrowed $100 million under this promissory note and an additional $100 million under a separate promissory note issued to Southern Company in November 2015.

On June 27, 2016, the Company received a capital contribution from Southern Company of $225 million, the proceeds of which were used to repay to Southern Company a portion of the promissory note issued in November 2015. As of December 31, 2016, the amount of outstanding promissory notes to Southern Company totaled $551 million.

Also, on December 14, 2016, the Company received a capital contribution from Southern Company of $400 million, the proceeds of which were used for general corporate purposes.

Other Obligations

In June 2016, the Company renewed a $10 million short-term note, which matures on June 30, 2017, bearing interest based on three-month LIBOR.

In September 2016, the Company entered into interest rate swaps to fix the variable interest rate on $900 million of the term loan entered into in March 2016.

In December 2016, the Company repaid $2.5 million of a $15 million short-term note, reducing the total short-term notes payable to $22.5 million.

Credit Rating Risk

At December 31, 2016, 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 have required or could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, energy price risk management, and transmission. At December 31, 2016, the maximum amount of potential collateral requirements under these contracts at a rating of BBB and/or Baa2 or BBB- and/or Baa3 was not material. The maximum potential collateral requirements at a rating below BBB- and/or Baa3 equaled approximately $243 million.

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power 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, a credit rating downgrade could impact the ability of the Company to access capital markets, and would be likely to impact the cost at which it does so.

On May 12, 2016, Fitch Ratings, Inc. (Fitch) downgraded the senior unsecured long-term debt rating of the Company to BBB+ from A- and revised the ratings outlook from negative to stable.

On January 10, 2017, S&P revised its consolidated credit rating outlook for Southern Company (including the Company) from negative to stable.

On February 6, 2017, Moody's placed the Company on a ratings review for potential downgrade. The Company's current rating for unsecured debt is Baa3.

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 a change in interest rates, the Company may enter into derivatives that have been designated as hedges. The weighted average interest rate on $891 million of long-term variable interest rate exposure at December 31, 2016 was 2.17%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $9 million at January 1, 2017. 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, 2016 when compared to the year ended December 31, 2015.

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:

	2016 Changes	2015 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (47)**	$ (45)
Contracts realized or settled	**29**	33
Current period changes(*)	**11**	(35)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (7)**	$ (47)

(*) 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:

	2016	2015
	mmBtu Volume	
	(in millions)	
Total hedge volume	**36**	32

For natural gas hedges, the weighted average swap contract cost above market prices was approximately $0.19 per mmBtu as of December 31, 2016 and $1.49 per mmBtu as of December 31, 2015. There were no options outstanding as of the reporting periods presented. The costs associated with natural gas hedges are recovered through the Company's ECMs.

At December 31, 2016 and 2015, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were 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.

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 of the fair value hierarchy. 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, 2016 were as follows:

	Fair Value Measurements December 31, 2016		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	(7)	(4)	(3)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (7)	$ (4)	$ (3)

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

Approximately $586 million will be required through December 31, 2017 to fund maturities of long-term debt, and $23 million will be required to fund maturities of short-term debt. See "Sources of Capital" herein for additional information.

The construction program of the Company is currently estimated to total $517 million for 2017, $241 million for 2018, $274 million for 2019, $305 million for 2020, and $230 million for 2021, which includes completion of the Kemper IGCC and post-in-service costs. Expenditures related to completion of the Kemper IGCC are currently estimated to be $254 million for 2017. These estimated program amounts also include capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these program amounts are $11 million, $5 million, $24 million, $29 million, and $58 million for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated environmental expenditures do not include potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" and – "Integrated Coal Gasification Combined Cycle" herein for additional information.

The Company also anticipates costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $32 million, $11 million, $6 million, $6 million, and $9 million for the years 2017, 2018, 2019, 2020, and 2021, respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" 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 the 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, the construction program includes the development and construction of the Kemper IGCC, a first-of-a-kind technology, which may result in revised estimates during construction. The ability to control costs and avoid cost overruns during the development and construction of new facilities is subject to a number of factors, including, but not limited to, changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, sustaining nitrogen supply, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

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, unrecognized tax benefits, pension and other post-retirement benefit plans, 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

Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 626	$ 1,325	$ 270	$ 723	$ 2,944
Interest	98	141	100	598	937
Preferred stock dividends[b]	2	3	3	—	8
Financial derivative obligations[c]	6	4	—	—	10
Unrecognized tax benefits[d]	465	—	—	—	465
Operating leases [e]	2	1	1	—	4
Capital leases[f]	7	13	13	76	109
Purchase commitments —					
Capital[g]	480	508	506	—	1,494
Fuel[h]	290	320	184	251	1,045
Long-term service agreements[i]	15	75	48	244	382
Pension and other postretirement benefits plans[j]	7	15	—	—	22
Total	$ 1,998	$ 2,405	$ 1,125	$ 1,892	$ 7,420

(a) All amounts are reflected based on final maturity dates except for amounts related to certain pollution control revenue bonds. Long-term debt principal for 2017 includes $40 million of pollution control revenue bonds that are classified on the balance sheet at December 31, 2016 as short-term since they are variable rate demand obligations that are supported by short-term credit facilities; however, the final maturity date is in 2028. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2017, 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 five-year period, including capital expenditures associated with environmental regulations. At December 31, 2016, 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" herein 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, 2016.

(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 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan and postretirement benefit plans contributions, financing activities, completion of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, storm damage cost recovery and repairs, and estimated construction and other plans and 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 environmental laws regulating emissions, discharges, and disposal to air, water, and land, and also changes in tax and other laws and regulations to which the Company is subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries;
- 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 last recession, population and business growth (and declines), the effects of energy conservation and efficiency 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;
- the ability to control costs and avoid cost overruns during the development, construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, sustaining nitrogen supply, contractor or supplier delay, non-performance under operating or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- 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;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- actions related to cost recovery for the Kemper IGCC, including the ultimate impact of the 2015 decision of the Mississippi Supreme Court, the Mississippi PSC's December 2015 rate order, and related legal or regulatory proceedings, Mississippi PSC review of the prudence of Kemper IGCC costs and approval of further permanent rate recovery plans, actions relating to proposed securitization, satisfaction of requirements to utilize grants, and the ultimate impact of the termination of the proposed sale of an interest in the Kemper IGCC to SMEPA;
- 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 cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, 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, 2016, 2015, and 2014
Mississippi Power Company 2016 Annual Report

	2016	2015	2014
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 859**	$ 776	$ 795
Wholesale revenues, non-affiliates	**261**	270	323
Wholesale revenues, affiliates	**26**	76	107
Other revenues	**17**	16	18
Total operating revenues	**1,163**	1,138	1,243
Operating Expenses:			
Fuel	**343**	443	574
Purchased power, non-affiliates	**5**	5	18
Purchased power, affiliates	**29**	7	25
Other operations and maintenance	**312**	274	271
Depreciation and amortization	**132**	123	97
Taxes other than income taxes	**109**	94	79
Estimated loss on Kemper IGCC	**428**	365	868
Total operating expenses	**1,358**	1,311	1,932
Operating Loss	**(195)**	(173)	(689)
Other Income and (Expense):			
Allowance for equity funds used during construction	**124**	110	136
Interest expense, net of amounts capitalized	**(74)**	(7)	(45)
Other income (expense), net	**(7)**	(8)	(14)
Total other income and (expense)	**43**	95	77
Loss Before Income Taxes	**(152)**	(78)	(612)
Income taxes (benefit)	**(104)**	(72)	(285)
Net Loss	**(48)**	(6)	(327)
Dividends on Preferred Stock	**2**	2	2
Net Loss After Dividends on Preferred Stock	**$ (50)**	$ (8)	$ (329)

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

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2016, 2015, and 2014
Mississippi Power Company 2016 Annual Report

	2016	2015	2014
		(in millions)	
Net Loss	**$ (48)**	$ (6)	$ (327)
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $1, $-, and $-, respectively	**1**	—	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**1**	1	1
Total other comprehensive income (loss)	**2**	1	1
Comprehensive Loss	**$ (46)**	$ (5)	$ (326)

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016, 2015, and 2014
Mississippi Power Company 2016 Annual Report

	2016	2015	2014
		(in millions)	
Operating Activities:			
Net loss	$ **(48)**	$ (6)	$ (327)
Adjustments to reconcile net loss to net cash provided from operating activities —			
Depreciation and amortization, total	**157**	126	104
Deferred income taxes	**(67)**	777	145
Investment tax credits	**—**	(210)	(38)
Allowance for equity funds used during construction	**(124)**	(110)	(136)
Pension and postretirement funding	**(47)**	—	(33)
Regulatory assets associated with Kemper IGCC	**(12)**	(61)	(72)
Estimated loss on Kemper IGCC	**428**	365	868
Income taxes receivable, non-current	**—**	(544)	—
Other, net	**(20)**	8	22
Changes in certain current assets and liabilities —			
-Receivables	**13**	28	(22)
-Prepaid income taxes	**39**	(35)	(50)
-Other current assets	**(8)**	(18)	(6)
-Accounts payable	**(14)**	(34)	33
-Accrued taxes	**14**	(11)	39
-Over recovered regulatory clause revenues	**(45)**	96	(18)
-Mirror CWIP	**—**	(271)	180
-Customer liability associated with Kemper refunds	**(73)**	73	—
-Other current liabilities	**36**	—	46
Net cash provided from operating activities	**229**	173	735
Investing Activities:			
Property additions	**(798)**	(857)	(1,257)
Investment in restricted cash	**—**	—	(11)
Distribution of restricted cash	**—**	—	11
Construction payables	**(26)**	(9)	(50)
Government grant proceeds	**137**	—	—
Other investing activities	**(10)**	(40)	(33)
Net cash used for investing activities	**(697)**	(906)	(1,340)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	**627**	277	451
Bonds — Other	**—**	—	23
Interest-bearing refundable deposit	**—**	—	125
Long-term debt issuance to parent company	**200**	275	220
Other long-term debt	**1,200**	—	250
Short-term borrowings	**—**	505	—
Redemptions —			
Short-term borrowings	**(478)**	(5)	—
Long-term debt to parent company	**(225)**	—	(220)
Bonds — Other	**—**	—	(34)
Senior notes	**(300)**	—	—
Other long-term debt	**(425)**	(350)	—
Return of capital	**—**	—	(220)
Other financing activities	**(5)**	(4)	(2)
Net cash provided from financing activities	**594**	698	593
Net Change in Cash and Cash Equivalents	**126**	(35)	(12)
Cash and Cash Equivalents at Beginning of Year	**98**	133	145
Cash and Cash Equivalents at End of Year	$ **224**	$ 98	$ 133
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $49, $66, and $69 capitalized, respectively)	$ **50**	$ 45	$ 7
Income taxes (net of refunds)	**(97)**	(33)	(379)
Noncash transactions —			
Accrued property additions at year-end	**78**	105	114
Issuance of promissory note to parent related to repayment of interest-bearing refundable deposits and accrued interest	**—**	301	—

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

BALANCE SHEETS
At December 31, 2016 and 2015
Mississippi Power Company 2016 Annual Report

Assets	2016	2015
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 224**	$ 98
Receivables —		
Customer accounts receivable	**29**	26
Unbilled revenues	**42**	36
Income taxes receivable, current	**544**	20
Other accounts and notes receivable	**14**	10
Affiliated	**15**	20
Fossil fuel stock	**100**	104
Materials and supplies, current	**76**	75
Other regulatory assets, current	**115**	95
Prepaid income taxes	**—**	39
Other current assets	**8**	8
Total current assets	**1,167**	531
Property, Plant, and Equipment:		
In service	**4,865**	4,886
Less accumulated provision for depreciation	**1,289**	1,262
Plant in service, net of depreciation	**3,576**	3,624
Construction work in progress	**2,545**	2,254
Total property, plant, and equipment	**6,121**	5,878
Other Property and Investments	**12**	11
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**361**	290
Other regulatory assets, deferred	**518**	525
Income taxes receivable, non-current	**—**	544
Other deferred charges and assets	**56**	61
Total deferred charges and other assets	**935**	1,420
Total Assets	**$ 8,235**	$ 7,840

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

BALANCE SHEETS
At December 31, 2016 and 2015
Mississippi Power Company 2016 Annual Report

Liabilities and Stockholder's Equity	**2016**	2015
	(in millions)	
Current Liabilities:		
Securities due within one year —		
Parent	**$ 551**	$ —
Other	**78**	728
Notes payable	**23**	500
Accounts payable —		
Affiliated	**62**	85
Other	**135**	135
Customer deposits	**16**	16
Accrued taxes	**99**	85
Unrecognized tax benefits, current	**383**	—
Accrued interest	**46**	18
Accrued compensation	**42**	37
Asset retirement obligations, current	**32**	22
Over recovered regulatory clause liabilities	**51**	96
Customer liability associated with Kemper refunds	**1**	73
Other current liabilities	**19**	41
Total current liabilities	**1,538**	1,836
Long-Term Debt (See accompanying statements)	**2,424**	1,886
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**756**	762
Employee benefit obligations	**115**	153
Asset retirement obligations, deferred	**146**	154
Unrecognized tax benefits, deferred	**—**	368
Other cost of removal obligations	**170**	165
Other regulatory liabilities, deferred	**84**	79
Other deferred credits and liabilities	**26**	45
Total deferred credits and other liabilities	**1,297**	1,726
Total Liabilities	**5,259**	5,448
Cumulative Redeemable Preferred Stock (See accompanying statements)	**33**	33
Common Stockholder's Equity (See accompanying statements)	**2,943**	2,359
Total Liabilities and Stockholder's Equity	**$ 8,235**	$ 7,840
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2016 and 2015
Mississippi Power Company 2016 Annual Report

	2016	2015	2016	2015
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
2.35% due 2016	$ —	$ 300		
5.60% due 2017	35	35		
5.55% due 2019	125	125		
1.63% to 5.40% due 2035-2042	680	680		
Adjustable rates (1.84% to 1.90% at 1/1/16) due 2016	—	425		
Adjustable rates (2.15% to 2.24% at 1/1/17) due 2018	1,200	—		
Total long-term notes payable	2,040	1,565		
Other long-term debt —				
Pollution control revenue bonds —				
5.15% due 2028	43	43		
Variable rates (0.83% to 0.87% at 1/1/17) due 2017	40	40		
Plant Daniel revenue bonds (7.13%) due 2021	270	270		
Long-term debt payable to parent company (2.27%) due 2017	551	576		
Total other long-term debt	904	929		
Capitalized lease obligations	74	77		
Unamortized debt premium	45	53		
Unamortized debt discount	(2)	(2)		
Unamortized debt issuance expense	(8)	(8)		
Total long-term debt (annual interest requirement — $102 million)	3,053	2,614		
Less amount due within one year	629	728		
Long-term debt excluding amount due within one year	2,424	1,886	44.9%	44.1%
Cumulative Redeemable Preferred Stock:				
$100 par value —				
Authorized — 1,244,139 shares				
Outstanding — 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $2 million)	33	33	0.6	0.8
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 1,130,000 shares				
Outstanding — 1,121,000 shares	38	38		
Paid-in capital	3,525	2,893		
Accumulated deficit	(616)	(566)		
Accumulated other comprehensive loss	(4)	(6)		
Total common stockholder's equity	2,943	2,359	54.5	55.1
Total Capitalization	$ 5,400	$ 4,278	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, 2016, 2015, and 2014
Mississippi Power Company 2016 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2013	1	$ 38	$ 2,377	$ (230)	$ (8)	$ 2,177
Net loss after dividends on preferred stock	—	—	—	(329)	—	(329)
Capital contributions from parent company	—	—	235	—	—	235
Other comprehensive income (loss)	—	—	—	—	1	1
Balance at December 31, 2014	1	38	2,612	(559)	(7)	2,084
Net loss after dividends on preferred stock	—	—	—	(8)	—	(8)
Capital contributions from parent company	—	—	281	—	—	281
Other comprehensive income (loss)	—	—	—	—	1	1
Other	—	—	—	1	—	1
Balance at December 31, 2015	**1**	**38**	**2,893**	**(566)**	**(6)**	**2,359**
Net loss after dividends on preferred stock	**—**	**—**	**—**	**(50)**	**—**	**(50)**
Capital contributions from parent company	**—**	**—**	**632**	**—**	**—**	**632**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**2**	**2**
Balance at December 31, 2016	**1**	**$ 38**	**$ 3,525**	**$ (616)**	**$ (4)**	**$ 2,943**

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

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Mississippi Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern LINC, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and the Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service 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. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC 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 and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The Company is subject to regulation by the FERC and the Mississippi PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply 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.

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers,* replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 11 for disclosures impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory* (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

In 2014, the FASB issued ASU No. 2014-15, *Presentation of Financial Statements-Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* (ASU 2014-15). ASU 2014-15 defines management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern within one year of the date the financial statements are issued and to provide related footnote disclosures including management's plans that alleviate substantial doubt. ASU 2014-15 became effective for fiscal years ending after December 15, 2016 and the Company has included the disclosures required by ASU 2014-15 in Note 6 under "Going Concern."

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 $231 million, $295 million, and $259 million during 2016, 2015, and 2014, 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 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 $13 million, $11 million, and $13 million in 2016, 2015, and 2014, respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility. There were no fuel purchases in 2016. Fuel purchases were $8 million and $34 million in 2015 and 2014, 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 $26 million, $27 million, and $31 million in 2016, 2015, and 2014, respectively. See Note 4 for additional information.

On June 27, 2016, the Company received a capital contribution from Southern Company of $225 million, the proceeds of which were used to repay to Southern Company a portion of the promissory note issued in November 2015. As of December 31, 2016, the amount of outstanding promissory notes to Southern Company totaled $551 million. Also, on December 14, 2016, the Company received a capital contribution from Southern Company of $400 million, the proceeds of which were used for general corporate purposes. See Note 6 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 2016, 2015, or 2014.

The traditional electric 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 accounting requirements 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:

	2016	2015	Note
		(in millions)	
Kemper IGCC	**$ 201**	$ 216	(h)
Retiree benefit plans – regulatory assets	**173**	163	(a,g)
Asset retirement obligations	**83**	70	(c)
Deferred income tax charges	**362**	291	(c)
Remaining net book value of retired assets	**53**	36	(b)
Property tax	**37**	27	(d)
Plant Daniel Units 3 and 4	**33**	29	(j)
Other regulatory assets	**42**	27	(e,g)
Fuel-hedging (realized and unrealized) losses	**7**	50	(f,g)
Property damage	**(68)**	(64)	(i)
Other cost of removal obligations	**(170)**	(167)	(c)
Other regulatory liabilities	**(16)**	(11)	(b)
Total regulatory assets (liabilities), net	**$ 737**	$ 667	

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) Other regulatory liabilities is comprised of numerous immaterial components including deferred income tax credits and other miscellaneous liabilities that are recorded and refunded or amortized as approved by the Mississippi PSC generally over periods not exceeding one year.

(c) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 49 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(d) The retail portion of property taxes is recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year. See Note 3 under "Retail Regulatory Matters – Ad Valorem Tax Adjustment" for additional information.

(e) Other regulatory assets is comprised of numerous immaterial components including vacation pay, loss on reacquired debt, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the Mississippi PSC over periods which may range up to 50 years.

(f) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three years. Upon final settlement, actual costs incurred are recovered through the ECM.

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

(h) Includes $97 million of regulatory assets currently in rates to be recovered over periods of two, seven, or 10 years. For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(i) For additional information, see Note 1 under "Provision for Property Damage."

(j) The difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term is deferred and amortized over a 10-year period beginning October 2021.

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 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 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270 million of the Kemper IGCC through the grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants). Through December 31, 2016, the Company has received grant funds of $382 million, of which $245 million of the Initial DOE Grants were 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, and $137 million received on April 8, 2016 (Additional DOE Grants), which are expected to be used to reduce future rate impacts. An additional $25 million is expected to be received for its initial operation. See Note 3 under "Kemper IGCC Schedule and Cost Estimate" for additional information.

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 projected 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 MRA electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.8% of the Company's total operating revenues in 2016 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Except as described above for the Company's cost-based MRA electric tariff customers, the Company has a diversified base of customers and no single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

See Note 3 under "Retail Regulatory Matters" for additional information.

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. 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 operations.

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 CWIP is not allowed in rates.

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

	2016	2015
	(in millions)	
Generation	$ **2,632**	$ 2,723
Transmission	**712**	688
Distribution	**916**	891
General	**520**	503
Plant acquisition adjustment	**85**	81
Total plant in service	$ **4,865**	$ 4,886

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 Kemper IGCC assets already placed in service and a portion of the railway track maintenance costs. The portion of railway track maintenance costs not charged to operations and maintenance expenses are charged to fuel stock and recovered through the Company's fuel clause. Through July 2015, all costs associated with the combined cycle and the associated common facilities portion of the Kemper IGCC, excluding the lignite mine, were deferred to a regulatory asset that is being recovered over 10 years beginning August 2015. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

Depreciation, Depletion, and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 4.2% in 2016, 4.7% in 2015, and 3.3% in 2014. The decrease in the 2016 depreciation rate is primarily due to fully depreciating and retiring the ARO at Plant Watson, partially offset by the increase in depreciation for the Plant Daniel scrubbers for a full year. The increase in the 2015 depreciation rate was primarily due to an ARO at Plant Watson incurred as a result of changes in environmental regulations. See "Asset Retirement Obligations and Other Costs of Removal" herein for additional information. Depreciation studies are conducted periodically to update the composite rates. The Mississippi PSC approved the 2014 study, with new rates effective January 1, 2015. 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, except for the Kemper IGCC assets in service.

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 in June 2013. Depreciation associated with fixed assets, amortization associated with rolling stock, and depletion associated with minerals and minerals rights is recognized and charged to fuel stock and is expected to be recovered through the Company's fuel clause. Through July 2015, depreciation associated with the combined cycle and the associated common facilities portion of the Kemper IGCC was deferred as a regulatory asset that is being recovered over 10 years beginning August 2015. See Note 3 under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" for additional information.

Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated 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. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. 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 liability for AROs primarily relates to facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in April 2015 (CCR Rule), principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, 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 and certain wireless communication towers. 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 operations 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 AROs included in the balance sheets are as follows:

	2016	2015
	(in millions)	
Balance at beginning of year	**$ 177**	$ 48
Liabilities incurred	**15**	101
Liabilities settled	**(23)**	(3)
Accretion	**5**	4
Cash flow revisions	**5**	27
Balance at end of year	**$ 179**	$ 177

The increase in liabilities incurred and cash flow revisions in 2015 primarily relate to an increase in AROs associated with facilities impacted by the CCR Rule located at Plant Watson and Plant Greene County.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2016 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates.

Allowance for Funds Used During Construction

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, 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 6.50%, 5.99%, and 6.91% for the years ended December 31, 2016, 2015, and 2014, respectively. AFUDC equity was $124 million, $110 million, and $136 million in 2016, 2015, and 2014, 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. Every three years the Mississippi PSC, the 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. 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 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. The Company made retail accruals of $4 million for 2016 and $3 million for each of 2015 and 2014. The Company also accrued $0.3 million annually in 2016, 2015, and 2014 for the wholesale jurisdiction. As of December 31, 2016, the property damage reserve balances were $66 million and $1 million for retail and wholesale, respectively.

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 used, 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 costs are recorded 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 coal is mined, and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates or capitalized as part of the Kemper IGCC costs if used for testing. The retail rate is approved by the Mississippi PSC and the wholesale rates are approved by the FERC. Emissions allowances granted by the 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 on the balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. 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 result 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 related to the Kemper IGCC are recorded in CWIP. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of operations. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 10 for additional information regarding derivatives.

Beginning in 2016, the Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company's collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2016 are immaterial.

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, and reclassifications for amounts included in net income.

Variable Interest Entities

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

The 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. As of December 31, 2016, the VIE consolidation resulted in an ARO asset and associated liability in the amounts of $20 million and $24 million, respectively. As of December 31, 2015, the VIE consolidation resulted in an ARO and an associated liability in the amounts of $21 million and $25 million, respectively. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). On December 19, 2016, the Company voluntarily contributed $47 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017. 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, 2017, no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

Assumptions used to determine net periodic costs:	2016	2015	2014
Pension plans			
Discount rate – benefit obligations	**4.69%**	4.17%	5.01%
Discount rate – interest costs	**3.97**	4.17	5.01
Discount rate – service costs	**5.04**	4.49	5.01
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**4.46**	3.59	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	**4.47%**	4.03%	4.85%
Discount rate – interest costs	**3.66**	4.03	4.85
Discount rate – service costs	**4.88**	4.38	4.85
Expected long-term return on plan assets	**7.07**	7.23	7.30
Annual salary increase	**4.46**	3.59	3.59

Assumptions used to determine benefit obligations:	2016	2015
Pension plans		
Discount rate	**4.44%**	4.69%
Annual salary increase	**4.46**	4.46
Other postretirement benefit plans		
Discount rate	**4.22%**	4.47%
Annual salary increase	**4.46**	4.46

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. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2016 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2025
Post-65 medical	5.00	4.50	2025
Post-65 prescription	10.00	4.50	2025

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, 2016 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 5	$ 4
Service and interest costs	—	—

Pension Plans

The total accumulated benefit obligation for the pension plans was $479 million at December 31, 2016 and $447 million at December 31, 2015. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 500**	$ 513
Service cost	**13**	13
Interest cost	**19**	21
Benefits paid	**(20)**	(22)
Actuarial (gain) loss	**22**	(25)
Balance at end of year	**534**	500
Change in plan assets		
Fair value of plan assets at beginning of year	**430**	446
Actual return (loss) on plan assets	**39**	4
Employer contributions	**50**	2
Benefits paid	**(20)**	(22)
Fair value of plan assets at end of year	**499**	430
Accrued liability	**$ (35)**	$ (70)

At December 31, 2016, the projected benefit obligations for the qualified and non-qualified pension plans were $504 million and $30 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's pension plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 154**	$ 144
Other current liabilities	**(3)**	(3)
Employee benefit obligations	**(32)**	(67)

Presented below are the amounts included in regulatory assets at December 31, 2016 and 2015 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 2017.

	2016	2015	**Estimated Amortization in 2017**
		(in millions)	
Prior service cost	**$ 3**	$ 2	**$ 1**
Net (gain) loss	**151**	142	**7**
Regulatory assets	**$ 154**	$ 144	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 144**	$ 151
Net (gain) loss	**16**	4
Change in prior service costs	**2**	—
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	(1)
Amortization of net gain (loss)	**(7)**	(10)
Total reclassification adjustments	**(8)**	(11)
Total change	**10**	(7)
Ending balance	**$ 154**	$ 144

Components of net periodic pension cost were as follows:

	2016	2015	2014
		(in millions)	
Service cost	**$ 13**	$ 13	$ 10
Interest cost	**19**	21	20
Expected return on plan assets	**(35)**	(33)	(29)
Recognized net (gain) loss	**7**	10	5
Net amortization	**1**	1	1
Net periodic pension cost	**$ 5**	$ 12	$ 7

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, 2016, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2017	$ 22
2018	23
2019	24
2020	26
2021	27
2022 to 2026	154

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 97**	$ 96
Service cost	**1**	1
Interest cost	**3**	4
Benefits paid	**(6)**	(5)
Actuarial (gain) loss	**1**	(1)
Plan amendment	**—**	1
Retiree drug subsidy	**1**	1
Balance at end of year	**97**	97
Change in plan assets		
Fair value of plan assets at beginning of year	**23**	24
Actual return (loss) on plan assets	**1**	—
Employer contributions	**4**	3
Benefits paid	**(5)**	(4)
Fair value of plan assets at end of year	**23**	23
Accrued liability	**$ (74)**	$ (74)

Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's other postretirement benefit plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 21**	$ 21
Other regulatory liabilities, deferred	**(2)**	(3)
Employee benefit obligations	**(74)**	(74)

Approximately $19 million and $18 million was included in net regulatory assets at December 31, 2016 and 2015, respectively, related to the net loss for the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost. The estimated amortization of such amounts for 2017 is $1 million.

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	**$ 18**	$ 16
Net (gain) loss	**2**	—
Change in prior service costs	**—**	3
Reclassification adjustments:		
Amortization of net gain (loss)	**(1)**	(1)
Total reclassification adjustments	**(1)**	(1)
Total change	**1**	2
Ending balance	**$ 19**	$ 18

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

	2016	2015	2014
		(in millions)	
Service cost	**$ 1**	$ 1	$ 1
Interest cost	**3**	4	4
Expected return on plan assets	**(1)**	(2)	(2)
Net amortization	**1**	1	—
Net periodic postretirement benefit cost	**$ 4**	$ 4	$ 3

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 millions)	
2017	$ 6	$ (1)	$ 5
2018	6	(1)	5
2019	7	(1)	6
2020	7	(1)	6
2021	7	(1)	6
2022 to 2026	36	(1)	35

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, 2016 and 2015, along with the targeted mix of assets for each plan, is presented below:

	Target	**2016**	2015
Pension plan assets:			
Domestic equity	26%	**29%**	30%
International equity	25	**22**	23
Fixed income	23	**29**	23
Special situations	3	**2**	2
Real estate investments	14	**13**	16
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	21%	**23%**	24%
International equity	20	**18**	18
Domestic fixed income	38	**43**	38
Special situations	3	**2**	2
Real estate investments	11	**10**	13
Private equity	7	**4**	5
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, 2016 and 2015. 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, private equity, and special situations investments.*** Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

The fair values of pension plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2015, investments in special situations were presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity(*)	$ 95	$ 44	$ —	$ —	$ 139
International equity(*)	58	51	—	—	109
Fixed income:					
U.S. Treasury, government, and agency bonds	—	28	—	—	28
Mortgage- and asset-backed securities	—	1	—	—	1
Corporate bonds	—	46	—	—	46
Pooled funds	—	25	—	—	25
Cash equivalents and other	47	—	—	—	47
Real estate investments	15	—	—	54	69
Special situations	—	—	—	8	8
Private equity	—	—	—	26	26
Total	$ 215	$ 195	$ —	$ 88	$ 498

(*) 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, 2015:	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)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity(*)	$ 76	$ 32	$ —	$ —	$ 108
International equity(*)	55	46	—	—	101
Fixed income:					
U.S. Treasury, government, and agency bonds	—	21	—	—	21
Mortgage- and asset-backed securities	—	9	—	—	9
Corporate bonds	—	53	—	—	53
Pooled funds	—	23	—	—	23
Cash equivalents and other	—	7	—	—	7
Real estate investments	14	—	—	57	71
Private equity	—	—	—	30	30
Total	$ 145	$ 191	$ —	$ 87	$ 423

(*) 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.

The fair values of other postretirement benefit plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

As of December 31, 2016:	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)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity(*)	$ 4	$ 2	$ —	$ —	$ 6
International equity(*)	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	5	—	—	5
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	2	—	—	—	2
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$ 9	$ 12	$ —	$ 3	$ 24

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

	Fair Value Measurements Using				
As of December 31, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity(*)	$ 3	$ 1	$ —	$ —	$ 4
International equity(*)	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	6	—	—	6
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	1	—	—	—	1
Real estate investments	1	—	—	3	4
Private equity	—	—	—	1	1
Total	$ 7	$ 12	$ —	$ 4	$ 23

(*) 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.

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 2016, 2015, and 2014 were $5 million each year.

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 occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. 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

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 affected sites. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through established regulatory mechanisms.

FERC Matters

Municipal and Rural Associations Tariff

In 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.

In 2014, the Company reached, and the FERC accepted, a settlement agreement with its wholesale customers for an estimated annual increase in the MRA cost-based tariff of approximately $10 million, effective May 1, 2014. Included in this settlement agreement was a mechanism allowing the Company to adjust the wholesale revenue requirement in a subsequent rate proceeding in the event the Kemper IGCC, or any substantial portion thereof, was placed in service before or after December 1, 2014. Therefore, the Company recorded a regulatory asset as a result of a portion of the Kemper IGCC being placed in service prior to the projected date, which was fully amortized as of December 31, 2015.

In May 2015, the FERC accepted a further settlement agreement between the Company and its wholesale customers to forgo a MRA cost-based electric tariff increase by, among other things, increasing the accrual of AFUDC and lowering the portion of CWIP in rate base, effective April 1, 2015, resulting in an estimated annual AFUDC increase of approximately $14 million, of which approximately $11 million is related to the Kemper IGCC.

On March 31, 2016, the Company reached a settlement agreement with its wholesale customers, which was subsequently approved by the FERC, for an increase in wholesale base revenues under the MRA cost-based electric tariff, primarily as a result of placing scrubbers for Plant Daniel Units 1 and 2 in service in November 2015. The settlement agreement became effective for services rendered beginning May 1, 2016, resulting in an estimated annual revenue increase of $7 million under the MRA cost-based electric tariff. Additionally, under the settlement agreement, the tariff customers agreed to similar regulatory treatment for MRA tariff ratemaking as the treatment approved for retail ratemaking through an order issued by the Mississippi PSC in December 2015 (In-Service Asset Rate Order). This regulatory treatment primarily includes (i) recovery of the Kemper IGCC assets currently operational and providing service to customers and other related costs, (ii) amortization of the Kemper IGCC-related regulatory assets included in rates under the settlement agreement over the 36 months ending April 30, 2019, (iii) Kemper IGCC-related expenses included in rates under the settlement agreement no longer being deferred and charged to expense, and (iv) removing all of the Kemper IGCC CWIP from rate base with a corresponding increase in accrual of AFUDC. The additional resulting AFUDC is estimated to be approximately $14 million through the Kemper IGCC's projected in-service date of mid-March 2017.

Fuel Cost Recovery

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective with the first billing cycle for September 2016, fuel rates decreased $11 million annually for wholesale MRA customers and $1 million annually for wholesale MB customers. At December 31, 2016 and 2015, the amount of over recovered wholesale MRA fuel costs were approximately $13 million and $24 million, respectively, which is included in over recovered regulatory clause liabilities, current in the balance sheets. Effective January 1, 2017, the wholesale MRA fuel rate increased $10 million annually.

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 should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Market-Based Rate Authority

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

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

Retail Regulatory Matters

General

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In 2013, the 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.

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 a projected revenue requirement, and the PEP lookback filing, which is filed after the end of the year and allows for review of the 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 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. In 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $5 million. Unresolved matters related to the 2010 PEP lookback filing, which remain under review, also impact the 2012 PEP lookback filing.

In 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9%, or $15 million, annually, effective March 19, 2013. The Company may be entitled to $3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

In 2014, 2015, and 2016, the Company submitted its annual PEP lookback filings for the prior years, which for 2013 and 2014 each indicated no surcharge or refund and for 2015 indicated a $5 million surcharge. On July 12, 2016 and November 15, 2016, the Company submitted its annual projected PEP filings for 2016 and 2017, respectively, which each indicated no change in rates. The Mississippi PSC suspended each of these filings to allow more time for review.

In 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.

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

Energy Efficiency

In 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.

On May 3, 2016, the Mississippi PSC issued an order approving the Company's Energy Efficiency Cost Rider Compliance filing, which reduced annual retail revenues by approximately $2 million effective with the first billing cycle for June 2016.

On November 30, 2016, the Company submitted its Energy Efficiency Cost Rider Compliance filing, which included an increase of $1 million in annual retail revenues. The ultimate outcome of this matter cannot be determined at this time.

Environmental Compliance Overview Plan

In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in November 2015. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. In 2014, the Company entered into a settlement agreement with the Sierra Club that, among other things, required the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges to the issuance of the CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which also occurred in 2014. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018 (and the units were retired in July 2016). The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015 (which occurred in April 2015) and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) no later than April 2016 (which occurred in February and March 2016, respectively) and begin operating those units solely on natural gas (which occurred in June and July 2016, respectively).

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. As of December 31, 2016, $17 million of Plant Greene County costs have been reclassified as regulatory assets and are expected to be recovered through the ECO plan and other existing cost recovery mechanisms over a period to be determined by the Mississippi PSC. The Mississippi PSC approved $41 million of costs that were reclassified to a regulatory asset associated with Plant Watson for amortization over a five-year period that began in July 2016. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

On August 17, 2016, the Mississippi PSC approved the Company's revised ECO plan filing for 2016, which requested the maximum 2% annual increase in revenues, approximately $18 million, primarily related to the Plant Daniel Units 1 and 2 scrubbers being placed in service in November 2015. The revised rates became effective with the first billing cycle for September 2016. Approximately $22 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2017 filing.

On February 14, 2017, the Company submitted its ECO plan filing for 2017, which requested an increase in annual revenues over 2016, capped at 2% of total retail revenues, of approximately $18 million, primarily related to the Plant Daniel Units 1 and 2 scrubbers placed in service in November 2015. The revenue requirement in excess of the 2%, approximately $27 million plus carrying costs, will be carried forward to the 2018 filing. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually. The Mississippi PSC approved the 2016 retail fuel cost recovery factor, effective January 5, 2016, which resulted in an annual revenue decrease of approximately $120 million. On August 17, 2016, the Mississippi PSC approved an additional decrease of $51 million annually in fuel cost recovery rates effective with the first billing cycle for September 2016. At December 31, 2016 and 2015, over recovered retail fuel costs were approximately $37 million and $71 million, respectively, which is included in over recovered regulatory clause liabilities, current in the balance sheets. On January 12, 2017, the Mississippi PSC approved the 2017 retail fuel cost recovery factor, effective February 2017 through January 2018, which will result in an annual revenue increase of approximately $55 million.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

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 17, 2016, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2016, which included an annual rate decrease of 0.07%, or $1 million in annual retail revenues, primarily due to the prior year over recovery.

System Restoration Rider

In October 2015, the Mississippi PSC approved the Company's 2015 SRR rate filing, which proposed that the SRR rate remain level at zero and the Company continue to accrue $3 million annually to the property damage reserve.

On February 1, 2016, the Company submitted its 2016 SRR rate filing which proposed no changes to either the SRR rate or the annual property damage reserve accrual. On February 19, 2016, the filing was suspended by the Mississippi PSC for review. The ultimate outcome of this matter cannot be determined at this time.

On February 3, 2017, the Company submitted its 2017 SRR rate filing, which proposed that the rate level remain at zero and the Company be allowed to accrue $4 million annually to the property damage reserve in 2017. The ultimate outcome of this matter cannot be determined at this time.

See Note 1 under "Provision for Property Damage" for additional information.

Storm Damage Cost Recovery

In connection with the damage associated with Hurricane Katrina, the Mississippi PSC authorized the issuance of system restoration bonds in 2006. In accordance with a Mississippi PSC order dated January 24, 2017, the Company has adjusted the System Restoration Charge implemented after Hurricane Katrina to zero. Upon completion of the proper defeasance process by the Mississippi State Bond Commission, the Company's obligations in relation to system restoration bonds issued after Hurricane Katrina in 2005 will be completely satisfied.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

The Kemper IGCC utilizes IGCC technology with an expected output capacity of 582 MWs. The Kemper IGCC is 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 in 2013. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion, net of $245 million of Initial 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. The Kemper IGCC was originally projected to be placed in service in May 2014. The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." The Company achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. The Company subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced and captured CO_2, and has produced sulfuric acid and ammonia, all of acceptable quality under the related off-take agreements. On February 20, 2017, the Company determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, the Company currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.

The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision discussed herein under "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order"), and actual costs incurred as of December 31, 2016, all of which include 100% of the costs for the Kemper IGCC, are as follows:

Cost Category	2010 Project Estimate[(a)]	Current Cost Estimate[(b)]	**Actual Costs**
		(in billions)	
Plant Subject to Cost Cap[(c)(e)]	$ 2.40	$ 5.64	**$ 5.44**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC[(d)]	0.17	0.79	**0.75**
Combined Cycle and Related Assets Placed in Service – Incremental[(e)]	—	0.04	**0.04**
General Exceptions	0.05	0.10	**0.09**
Deferred Costs[(e)]	—	0.22	**0.21**
Additional DOE Grants[(f)]	—	(0.14)	**(0.14)**
Total Kemper IGCC[(g)]	$ 2.97	$ 6.99	**$ 6.73**

(a) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities approved in 2011 by the Mississippi PSC, as well as the lignite mine and equipment, AFUDC, and general exceptions.

(b) Amounts in the Current Cost Estimate include certain estimated post-in-service costs which are expected to be subject to the cost cap.

(c) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the Initial DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO2 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 customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The Current Cost Estimate and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014 that are subject to the $2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information.

(d) The Company's 2010 Project Estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC as described in "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order." The Current Cost Estimate also reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction. See "FERC Matters" herein for additional information.

(e) Non-capital Kemper IGCC-related costs incurred during construction were initially deferred as regulatory assets. Some of these costs are now included in rates and are being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2016. The wholesale portion of debt carrying costs, whether deferred or recognized through income, is not included in the Current Cost Estimate and the Actual Costs at December 31, 2016. See "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein for additional information.

(f) On April 8, 2016, the Company received approximately $137 million in Additional DOE Grants, which are expected to be used to reduce future rate impacts for customers.

(g) The Current Cost Estimate and the Actual Costs include $2.76 billion that will not be recovered for costs above the cost cap, $0.83 billion of investment costs included in current rates for the combined cycle and related assets in service, and $0.08 billion of costs that were previously expensed for the combined cycle and related assets in service. The Current Cost Estimate and the Actual Costs exclude $0.25 billion of costs not included in current rates for post-June 2013 mine operations, the lignite fuel inventory, and the nitrogen plant capital lease, which will be included in the 2017 Rate Case to be filed by June 3, 2017. See Note 1 under "Fuel Inventory," Note 6 under "Capital Leases," and "Rate Recovery of Kemper IGCC Costs – 2017 Rate Case" herein for additional information.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2016, $3.67 billion was included in property, plant, and equipment (which is net of the Initial DOE Grants, the Additional DOE Grants, and estimated probable losses of $2.84 billion), $6 million in other property and investments, $75 million in fossil fuel stock, $47 million in materials and supplies, $29 million in other regulatory assets, current, $172 million in other regulatory assets, deferred, $3 million in other current assets, and $14 million in other deferred charges and assets in the balance sheet.

The Company does not intend to seek rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate of $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016, 2015, and 2014, respectively. Since 2012, in the aggregate, the Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016. The increases to the cost estimate in 2016 primarily reflect $186 million for the extension of the Kemper IGCC's projected in-service date from August 31, 2016 to March 15, 2017 and $162 million for increased efforts related to operational readiness and challenges in start-up and commissioning activities, including the cost of repairs and modifications to both gasifiers, mechanical improvements to coal feed and ash management systems, and outage work, as well as certain post-in-service costs expected to be subject to the cost cap.

In addition to the current construction cost estimate, the Company is identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap.

Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month. For additional information, see "2015 Rate Case" herein.

Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). Any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, cannot now be determined but could result in further material charges that could have a material impact on the Company's results of operations, financial condition, and liquidity.

As of December 31, 2016, in addition to the $2.76 billion of costs above the Mississippi PSC's $2.88 billion cost cap that have been recognized as a charge to income, the Company had incurred approximately $1.99 billion in costs subject to the cost cap and approximately $1.46 billion in Cost Cap Exceptions related to the construction and start-up of the Kemper IGCC that are not included in current rates. These costs primarily relate to the following:

Cost Category	Actual Costs
	(in billions)
Gasifiers and Gas Clean-up Facilities	$ 1.88
Lignite Mine Facility	0.31
CO_2 Pipeline Facilities	0.11
Combined Cycle and Common Facilities	0.16
AFUDC	0.69
General exceptions	0.07
Plant inventory	0.03
Lignite inventory	0.08
Regulatory and other deferred assets	0.12
Subtotal	3.45
Additional DOE Grants	(0.14)
Total	**$ 3.31**

Of these amounts, approximately 29% is related to wholesale and approximately 71% is related to retail, including the 15% portion that was previously contracted to be sold to SMEPA. The Company and its wholesale customers have generally agreed to the similar regulatory treatment for wholesale tariff purposes as approved by the Mississippi PSC for retail for Kemper IGCC-related costs. See "FERC Matters – Municipal and Rural Associations Tariff" and "Termination of Proposed Sale of Undivided Interest" herein for further information.

Prudence

On August 17, 2016, the Mississippi PSC issued an order establishing a discovery docket to manage all filings related to the prudence of the Kemper IGCC. On October 3, 2016, the Company made a required compliance filing, which included a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate. On November 17, 2016, the Company submitted a supplemental filing to the October 3, 2016 compliance filing to present revised non-fuel operations and maintenance expense projections for the first year after the Kemper IGCC is placed in service. This supplemental filing included approximately $68 million in additional estimated operations and maintenance costs expected to be required to support the operations of the Kemper IGCC during that period. The Company will not seek recovery of the $68 million in additional estimated costs from customers if incurred.

The Company expects the Mississippi PSC to address these matters in connection with the 2017 Rate Case.

Economic Viability Analysis

In the fourth quarter 2016, as a part of its Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected.

As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings discussed above, on February 21, 2017, the Company filed an updated project economic viability analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order confirming authorization of the Kemper IGCC. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

The Company expects the Mississippi PSC to address this matter in connection with the 2017 Rate Case.

2017 Accounting Order Request

After the remainder of the plant is placed in service, AFUDC equity of approximately $11 million per month will no longer be recorded in income, and the Company expects to incur approximately $25 million per month in depreciation, taxes, operations and maintenance expenses, interest expense, and regulatory costs in excess of current rates. The Company expects to file a request for authority from the Mississippi PSC and the FERC to defer all Kemper IGCC costs incurred after the in-service date that cannot be capitalized, are not included in current rates, and are not required to be charged against earnings as a result of the $2.88 billion cost cap until such time as the Mississippi PSC completes its review and includes the resulting allowable costs in rates. In the event that the Mississippi PSC does not grant the Company's request, these monthly expenses will be charged to income as incurred and will not be recoverable through rates.

2017 Rate Case

The Company continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. The Company also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein and under "Prudence," "Lignite Mine and CO_2 Pipeline Facilities," "Termination of Proposed Sale of Undivided Interest," "Bonus Depreciation," "Investment Tax Credits," and "Section 174 Research and Experimental Deduction," these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

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 in 2013. The Company expects to utilize this legislation to securitize prudently-incurred qualifying facility costs in excess of the certificated cost estimate of $2.4 billion. Qualifying facility costs include, but are not limited to, pre-construction costs, construction costs, regulatory costs, and accrued AFUDC. The Court's decision regarding the 2013 MPSC Rate Order did not impact the Company's ability to utilize alternate financing through securitization or the February 2013 legislation.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, the Company is developing both a traditional rate case requesting full cost recovery of the amounts not currently in rates and a rate mitigation plan that together represent the Company's probable filing strategy. The Company also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both the Company and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on the Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, the Company intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

The Company has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

2015 Rate Case

On August 13, 2015, the Mississippi PSC approved the Company's request for interim rates, which presented an alternative rate proposal (In-Service Asset Proposal) designed to recover the Company's costs associated with the Kemper IGCC assets that are commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs. The interim rates were designed to collect approximately $159 million annually and became effective in September 2015, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued the In-Service Asset Rate Order adopting in full a stipulation (2015 Stipulation) entered into between the Company and the MPUS regarding the In-Service Asset Proposal. The In-Service Asset Rate Order provided for retail rate recovery of an annual revenue requirement of approximately $126 million, based on the Company's actual average capital structure, with a maximum common equity percentage of 49.733%, a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excluded the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA but reserved the Company's right to seek recovery in a future proceeding. See "Termination of Proposed Sale of Undivided Interest" herein for additional information. The Company is required to file the 2017 Rate Case by June 3, 2017.

With implementation of the new rates on December 17, 2015, the interim rates were terminated and, in March 2016, the Company completed customer refunds of approximately $11 million for the difference between the interim rates collected and the permanent rates.

2013 MPSC Rate Order

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 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. In March 2013, the Mississippi PSC issued a 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 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service, based on a mirror CWIP methodology (Mirror CWIP rate).

On February 12, 2015, the Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the

2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. On July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015 and required the fourth quarter 2015 refund of the $342 million collected under the 2013 MPSC Rate Order, along with associated carrying costs of $29 million. The Court's decision did not impact the 2012 MPSC CPCN Order or the February 2013 legislation described above.

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. Through December 31, 2016, AFUDC recorded since the original May 2014 estimated in-service date for the Kemper IGCC has totaled $398 million, which will continue to accrue at approximately $16 million per month until the remainder of the plant is placed in service. The Company has not recorded any AFUDC on Kemper IGCC costs in excess of the $2.88 billion cost cap, except for Cost Cap Exception amounts.

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 including availability factor, heat rate, lignite heat content, and chemical revenue based upon assumptions in the Company's petition for the CPCN. The Company expects the Mississippi PSC to apply operational parameters in connection with the 2017 Rate Case and future proceedings related to the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or the Company incurs additional costs to satisfy such parameters, there could be a material adverse impact on the Company's financial statements. See "Prudence" herein for additional information.

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset through the in-service date, subject to review of such costs by the Mississippi PSC. Such costs include, but are not limited to, carrying costs on Kemper IGCC assets currently placed in service, costs associated with Mississippi PSC and MPUS consultants, prudence costs, legal fees, and operating expenses associated with assets placed in service.

In August 2014, the Company requested confirmation by the Mississippi PSC of the Company's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. 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. Beginning in the third quarter 2015 and the second quarter 2016, in connection with the implementation of retail and wholesale rates, respectively, the Company began expensing certain ongoing project costs and certain retail debt carrying costs (associated with assets placed in service and other non-CWIP accounts) that previously were deferred as regulatory assets and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees. The amortization periods for these regulatory assets vary from two years to 10 years as set forth in the In-Service Asset Rate Order and the settlement agreement with wholesale customers. As of December 31, 2016, the balance associated with these regulatory assets was $97 million, of which $29 million is included in current assets. Other regulatory assets associated with the remainder of the Kemper IGCC totaled $104 million as of December 31, 2016. The amortization period for these assets is expected to be determined by the Mississippi PSC in the 2017 Rate Case. See "FERC Matters" herein for additional information related to the 2016 settlement agreement with wholesale customers.

The In-Service Asset Rate Order requires the Company to submit an annual true-up calculation of its actual cost of capital, compared to the stipulated total cost of capital, with the first occurring as of May 31, 2016. At December 31, 2016, the Company's related regulatory liability included in its balance sheet totaled approximately $7 million. See "2015 Rate Case" herein for additional information.

Also see Note 1 under "Regulatory Assets and Liabilities" for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company owns 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 in June 2013.

In 2010, the Company executed a 40-year management fee contract with Liberty Fuels, which developed, constructed, and is operating and managing 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" and "Variable Interest Entities" for additional information.

In addition, the Company has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company entered into agreements with Denbury Onshore (Denbury) and Treetop Midstream Services, LLC (Treetop), pursuant to which Denbury would purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop would purchase 30% of the CO_2 captured from the Kemper IGCC. On June 3, 2016, the Company cancelled its contract with Treetop and amended its contract with Denbury to reflect, among other things, Denbury's agreement to purchase 100% of the CO_2 captured from the Kemper IGCC, an initial contract term of 16 years, and termination rights if the Company has not satisfied its contractual obligation to deliver captured CO_2 by July 1, 2017, in addition to Denbury's existing termination rights in the event of a change in law, force majeure, or an event of default by the Company. Any termination or material modification of the agreement with Denbury could impact the operations of the Kemper IGCC and result in a material reduction in the Company's revenues to the extent the Company is not able to enter into other similar contractual arrangements or otherwise sequester the CO_2 produced. Additionally, sustained oil price reductions could result in significantly lower revenues than the Company originally forecasted to be available to offset customer rate impacts, which could have a material impact on the Company's financial statements.

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

Termination of Proposed Sale of Undivided Interest

In 2010 and as amended in 2012, the Company and SMEPA entered into an agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC (15% Undivided Interest). On May 20, 2015, SMEPA notified the Company of its termination of the agreement. The Company previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, the Company issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures on December 1, 2017.

Litigation

On April 26, 2016, a complaint against the Company was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. On August 12, 2016, Southern Company and the Company removed the case to the U.S. District Court for the Southern District of Mississippi. The plaintiffs filed a request to remand the case back to state court, which was granted on November 17, 2016. The individual plaintiff, John Carlton Dean, alleges that the Company and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that the Company and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper IGCC and that these alleged breaches have unjustly enriched the Company and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper IGCC; ask the Circuit Court to revoke any licenses or certificates authorizing the Company or Southern Company to engage in any business related to the Kemper IGCC in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper IGCC costs from being charged to customers through electric rates. On December 7, 2016, Southern Company and the Company filed motions to dismiss.

On June 9, 2016, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a complaint against the Company, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint relates to the cancelled CO_2 contract with Treetop and alleges fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of the Company, Southern Company, and SCS and seeks compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, the Company, and SCS have moved to compel arbitration pursuant to the terms of the CO_2 contract.

The Company believes these legal challenges have no merit; however, an adverse outcome in these proceedings could have a material impact on the Company's results of operations, financial condition, and liquidity. The Company will vigorously defend itself in these matters, and the ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In 2008, the 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. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of bonus depreciation included in the PATH Act is expected to result in approximately $20 million of positive cash flows for the 2016 tax year, which was not all realized in 2016 due to a projected consolidated net operating loss (NOL) for Southern Company. Dependent upon placing the remainder of the Kemper IGCC in service by December 31, 2017, the Company expects approximately $370 million of positive cash flows from bonus depreciation for the 2017 tax year, which may not all be realized in 2017 due to additional NOL projections for the 2017 tax year. See "Kemper IGCC Schedule and Cost Estimate" herein and Note 5 under "Current and Deferred Income Taxes – Net Operating Loss" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Investment Tax Credits

The 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. These tax credits were dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In addition, 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 was also a requirement of the Phase II credits. As a result of schedule extensions for the Kemper IGCC, the Phase I tax credits were recaptured in 2013 and the Phase II tax credits were recaptured in 2015.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, has reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and has filed amended federal income tax returns for 2008 through 2013 to also include such deductions. The Kemper IGCC is based on first-of-a-kind technology, and Southern Company believes that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, the Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of December 31, 2016. See Note 5 under "Unrecognized Tax Benefits" for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter 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, 2016, 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	CWIP
		(in millions)		
Greene County				
Units 1 and 2	40%	$ 165	$ 48	$ —
Daniel				
Units 1 and 2	50%	$ 695	$ 173	$ 15

The Company's proportionate share of plant operating expenses is included in the statements of operations and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. 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:

	2016	2015	2014
		(in millions)	
Federal —			
Current	**$ (31)**	$ (768)	$ (431)
Deferred	**(60)**	704	183
	(91)	(64)	(248)
State —			
Current	**(6)**	(81)	1
Deferred	**(7)**	73	(38)
	(13)	(8)	(37)
Total	**$ (104)**	$ (72)	$ (285)

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:

	2016	2015
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 386**	$ 1,618
Property basis difference	**852**	—
Regulatory assets associated with AROs	**72**	71
Pensions and other benefits	**49**	30
Regulatory assets associated with employee benefit obligations	**70**	66
Regulatory assets associated with the Kemper IGCC	**82**	86
Rate differential	**144**	115
Other	**125**	176
Total	**1,780**	2,162
Deferred tax assets —		
Fuel clause over recovered	**26**	51
Estimated loss on Kemper IGCC	**484**	451
Pension and other benefits	**96**	92
Federal NOL	**109**	17
Property insurance	**27**	25
Premium on long-term debt	**14**	18
AROs	**72**	71
Property basis difference	**—**	451
Deferred state tax assets	**113**	152
Deferred federal tax assets	**31**	31
Federal effect of state deferred taxes	**19**	8
Other	**33**	33
Total	**1,024**	1,400
Total deferred tax liabilities, net	**756**	762
Accumulated deferred income taxes	**$ 756**	$ 762

The application of bonus depreciation provisions in current tax law significantly increased deferred tax liabilities related to accelerated depreciation.

At December 31, 2016, the tax-related regulatory assets were $362 million. These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2016, the tax-related regulatory liabilities were $7 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and unamortized ITCs.

In accordance with regulatory requirements, deferred federal 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 operations. Credits for non-Kemper IGCC related deferred ITCs amortized in this manner amounted to $1 million in each of 2016, 2015, and 2014.

At December 31, 2016, the Company had state of Mississippi NOL carryforwards totaling approximately $3 billion, resulting in deferred tax assets of approximately $112 million. The NOLs will expire between 2032 and 2037.

Effective Tax Rate

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

	2016	2015	2014
Federal statutory rate	**(35.0)%**	(35.0)%	(35.0)%
State income tax, net of federal deduction	**(5.7)**	(6.3)	(4.0)
Non-deductible book depreciation	**0.7**	1.3	0.1
AFUDC-equity	**(28.5)**	(49.6)	(7.8)
Other	**—**	(2.9)	0.1
Effective income tax rate (benefit rate)	**(68.5)%**	(92.5)%	(46.6)%

The decrease in the Company's 2016 effective tax rate (benefit rate), as compared to 2015, is primarily due to an increase in estimated losses associated with the Kemper IGCC and an increase in non-taxable AFUDC equity. The increase in the Company's 2015 effective tax rate (benefit rate), as compared to 2014, is primarily due to a decrease in estimated losses associated with the Kemper IGCC, partially offset by a decrease in non-taxable AFUDC equity.

On March 30, 2016, the FASB issued ASU 2016-09, which changes the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

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

	2016	2015	2014
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 421**	$ 165	$ 4
Tax positions increase from current periods	**26**	32	58
Tax positions increase from prior periods	**18**	224	103
Balance at end of year	**$ 465**	$ 421	$ 165

The tax positions increases from current periods and prior periods for 2016, 2015 and 2014 relate to deductions for R&E expenditures associated with the Kemper IGCC. See "Section 174 Research and Experimental Deduction" herein for additional information.

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

	2016	2015	2014
		(in millions)	
Tax positions impacting the effective tax rate	**$ 1**	$ (2)	$ 4
Tax positions not impacting the effective tax rate	**464**	423	161
Balance of unrecognized tax benefits	**$ 465**	$ 421	$ 165

The tax positions not impacting the effective tax rate relate to deductions for R&E expenditures associated with the Kemper IGCC. See "Section 174 Research and Experimental Deduction" herein for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2016	2015	2014
		(in millions)	
Interest accrued at beginning of year	**$ 13**	$ 3	$ 1
Interest accrued during the year	**15**	10	2
Balance at end of year	**$ 28**	$ 13	$ 3

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

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits and U.S. Congress Joint Committee on Taxation approval of the R&E expenditures associated with the Kemper IGCC could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined. See "Section 174 Research and Experimental Deduction" herein for additional information.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013, 2014, and 2015 federal income tax returns and has received partial acceptance letters from the IRS; however, the IRS has not finalized its audits. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, reflected deductions for R&E expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and filed amended federal income tax returns for 2008 through 2013 to also include such deductions.

The Kemper IGCC is based on first-of-a-kind technology, and Southern Company and the Company believe that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, the Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million and associated interest of $28 million as of December 31, 2016. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

6. FINANCING

Going Concern

As of December 31, 2016, the Company's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. The Company expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, the Company intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, the Company has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, the Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company, consistent with the requirements of ASU 2014-15. See Note 1 under "Recently Issued Accounting Standards" for additional information regarding ASU 2014-15.

Parent Company Loans and Equity Contributions

On January 28, 2016, the Company issued a promissory note for up to $275 million to Southern Company, which matures in December 2017, bearing interest based on one-month LIBOR. During 2016, the Company borrowed $100 million under this promissory note and an additional $100 million under a separate promissory note issued to Southern Company in November 2015.

On June 27, 2016, the Company received a capital contribution from Southern Company of $225 million, the proceeds of which were used to repay to Southern Company a portion of the promissory note issued in November 2015. Also, on December 14, 2016, the Company received a capital contribution from Southern Company of $400 million, the proceeds of which were used for general corporate purposes. As of December 31, 2016 and 2015, the amount of outstanding promissory notes to Southern Company totaled $551 million and $576 million, respectively.

Bank Term Loans

In March 2016, the Company entered into an unsecured term loan agreement with a syndicate of financial institutions for an aggregate amount of $1.2 billion. The Company borrowed $900 million in March 2016 under the term loan agreement and the remaining $300 million in October 2016. The Company used the initial proceeds to repay $900 million in maturing bank loans in March 2016 and the remaining $300 million to repay at maturity the Company's Series 2011A 2.35% Senior Notes due October 15, 2016. The term loan pursuant to this agreement matures on April 1, 2018 and bears interest based on one-month LIBOR.

This bank loan has a covenant that limits debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes any long-term debt payable to affiliated trusts, other hybrid securities, and any securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2016, the Company was in compliance with its debt limit.

At December 31, 2016, the Company had a total of $1.2 billion in bank loans outstanding. At December 31, 2015, the Company had a total of $900 million in bank loans outstanding, including $475 million classified as notes payable and $425 million classified as securities due within one year.

Senior Notes

At December 31, 2016 and 2015, the Company had $790 million and $1.1 billion of senior notes outstanding, respectively, which included senior notes due within one year. These senior notes are effectively subordinated to the 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. These bonds are secured by Plant Daniel Units 3 and 4 and certain related personal property. The bonds were recorded at fair value as of the date of assumption, or $346 million, reflecting a premium of $76 million. See "Assets Subject to Lien" herein for additional information.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2016 and 2015 was as follows:

	2016	**2015**
	(in millions)	
Parent company loans	**$ 551**	$ —
Senior notes	**35**	300
Bank term loans	**—**	425
Pollution control revenue bonds(*)	**40**	—
Capitalized leases	**3**	3
Outstanding at December 31	**$ 629**	$ 728

(*) Pollution control revenue bonds are classified as short term since they are variable rate demand obligations that are supported by short-term credit facilities; however, the final maturity date is in 2028.

Maturities through 2021 applicable to total long-term debt are as follows: $629 million in 2017, $1.2 billion in 2018, $128 million in 2019, $10 million in 2020, and $274 million in 2021.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of pollution control 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, 2016 and 2015 was $83 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.

The Company had $50 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2016 and 2015. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Capital Leases

In 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 at December 31, 2016 and 2015 of $74 million and $77 million, respectively, with an annual interest rate of 4.9% for both years. 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 2016 were $7 million and will be $7 million each year thereafter. Amortization of the capital lease asset for the air separation unit will begin when the Kemper IGCC is placed in service. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

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 related personal property. 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. See "Plant Daniel Revenue Bonds" herein for additional information.

Outstanding Classes of Capital Stock

The Company currently has preferred stock (including depositary shares which represent one-fourth of a share of preferred stock) and common stock authorized and outstanding. The preferred stock of the Company contains a feature that allows the holders to elect a majority of the Company's board of directors if preferred 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. Information for each outstanding series is in the table below:

Preferred Stock	Par Value/ Stated Capital Per Share	Shares Outstanding	Redemption Price Per Share
4.40% Preferred Stock	$ 100	8,867	$ 104.32
4.60% Preferred Stock	$ 100	8,643	$ 107.00
4.72% Preferred Stock	$ 100	16,700	$ 102.25
5.25% Preferred Stock(*)	$ 100	300,000	$ 100.00

(*) There are 1,200,000 outstanding depositary shares, each representing one-fourth of a share of the 5.25% preferred 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, 2016, committed credit arrangements with banks were as follows:

Expires			Executable Term Loans		Expires Within One Year	
2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)	*(in millions)*		*(in millions)*		*(in millions)*	
$173	$173	$150	$—	$13	$13	$160

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Most of these bank 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 bank 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 any securitized debt relating to the securitization of certain costs of the Kemper IGCC.

A portion of the $150 million unused credit with banks is allocated to provide liquidity support to the Company's 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, 2016 was $40 million.

At December 31, 2016 and 2015, there was no commercial paper debt outstanding.

At December 31, 2016 and 2015, there was $23 million and $500 million, respectively, of 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 2016, 2015, and 2014, the Company incurred fuel expense of $343 million, $443 million, and $574 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 as of December 31, 2016 of $41 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 traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric 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 electric 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 $3 million, $5 million, and $10 million for 2016, 2015, and 2014, respectively.

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. The Company has one remaining operating lease which 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 50% share of the lease costs, charged to fuel stock and recovered through the fuel cost recovery clause, was $2 million in 2016, $2 million in 2015, and $3 million in 2014. The Company's annual railcar lease payments for 2017 will be approximately $1 million. Lease obligations for the period 2018 and thereafter are immaterial.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plant Daniel. The Company's 50% share of the leases for fuel handling was charged to fuel handling expense annually from 2014 through 2016; however, those amounts were immaterial for the reporting period. The Company's annual lease payments through 2020 are expected to be immaterial for fuel handling equipment.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2016, there were 220 current and former employees participating in the stock option and performance share unit programs.

Stock Options

Through 2009, stock-based compensation granted to employees consisted exclusively of non-qualified stock options. The exercise price for stock options granted equaled the stock price of Southern Company common stock on the date of grant. Stock options vest on a pro rata basis over a maximum period of three years from the date of grant or immediately upon the retirement or death of the employee. Options expire no later than 10 years after the grant date. All unvested stock options vest immediately upon a change in control where Southern Company is not the surviving corporation. Compensation expense is generally recognized on a straight-line basis over the three-year vesting period with the exception of employees that are retirement eligible at the grant date and employees that will become retirement eligible during the vesting period. Compensation expense in those instances is recognized at the grant date for employees that are retirement eligible and through the date of retirement eligibility for those employees that become retirement eligible during the vesting period. In 2015, Southern Company discontinued the granting of stock options.

The weighted average grant-date fair value of stock options granted during 2014 derived using the Black-Scholes stock option pricing model was $2.20.

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2016, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2016, 2015, and 2014 was $4 million, $3 million, and $5 million, respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $2 million, $1 million, and $2 million for the years ended December 31, 2016, 2015, and 2014, respectively. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2016, the aggregate intrinsic value for the options outstanding and options exercisable was $6 million and $5 million, respectively.

Performance Share Units

From 2010 through 2014, stock-based compensation granted to employees included performance share units in addition to stock options. Beginning in 2015, stock-based compensation consisted exclusively of performance share units. Performance share units granted to employees vest at the end of a three-year performance period. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

The performance goal for all performance share units issued from 2010 through 2014 was based on the total shareholder return (TSR) for Southern Company common stock during the three-year performance period as compared to a group of industry peers.

For these performance share units, at the end of three years, active employees receive shares based on Southern Company's performance while retired employees receive a pro rata number of shares based on the actual months of service during the performance period prior to retirement. The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common 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.

Beginning in 2015, Southern Company issued two additional types of performance share units to employees in addition to the TSR-based awards. These included performance share units with performance goals based on cumulative earnings per share (EPS) over the performance period and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period. The EPS-based and ROE-based awards each represent 25% of total target grant date fair value of the performance share unit awards granted. The remaining 50% of the target grant date fair value consists of TSR-based awards. In contrast to the Monte Carlo simulation model used to determine the fair value of the TSR-based awards, the fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three-year performance period initially assuming a 100% payout at the end of the performance period. The TSR-based performance share units, along with the EPS-based and ROE-based awards, vest immediately upon the retirement of the employee. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

For the years ended December 31, 2016, 2015, and 2014, employees of the Company were granted performance share units of 62,435, 53,909, and 49,579, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2016, 2015, and 2014, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $45.17, $46.41, and $37.54, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2016 and 2015 was $48.84 and $47.77, respectively.

For the years ended December 31, 2016, 2015, and 2014, total compensation cost for performance share units recognized in income was $4 million, $4 million, and $2 million, respectively, with the related tax benefit also recognized in income of $1 million, $2 million, and $1 million, respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2016, $1 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 22 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, 2016, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 3	$ —	$ 3
Interest rate derivatives	—	3	—	3
Cash equivalents	206	—	—	206
Total	$ 206	$ 6	$ —	$ 212
Liabilities:				
Energy-related derivatives	$ —	$ 10	$ —	$ 10

As of December 31, 2015, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Cash equivalents	$ 52	$ —	$ —	$ 52
Liabilities:				
Energy-related derivatives	$ —	$ 47	$ —	$ 47

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. Foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. 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, 2016 and 2015, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	**Fair Value**
	(in millions)	
Long-term debt:		
2016	**$ 2,979**	**$ 2,922**
2015	$ 2,537	$ 2,413

The fair values are determined using 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. 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 net basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating 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 energy-related commodity prices. 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.

Energy-related derivative contracts are accounted for under one of the following 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.
- *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 operations 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, 2016, the net volume of energy-related derivative contracts for natural gas positions totaled 36 million mmBtu for the Company, with the longest hedge date of 2020 over which the Company is hedging its exposure to the variability in future cash flows for forecasted transactions.

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, 2016, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2016
	(in millions)				*(in millions)*
Cash Flow Hedges of Existing Debt	$ 900	1-month LIBOR	0.79%	March 2018	$ 3

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2017 are $2 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2022.

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may 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. At December 31, 2016, fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with counterparties. At December 31, 2015, the fair value amounts of derivative instruments were presented gross on the balance sheets.

At December 31, 2016 and 2015, the fair value of energy-related derivatives and interest rate derivatives was reflected on the balance sheets as follows:

	2016		2015	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	Assets	Liabilities
		(in millions)		
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 2**	**$ 6**	$ —	$ 29
Other deferred charges and assets/Other deferred credits and liabilities	**2**	**5**	—	18
Total derivatives designated as hedging instruments for regulatory purposes	**$ 4**	**$ 11**	$ —	$ 47
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Interest rate derivatives:				
Other current assets/Other current liabilities	**$ 2**	**$ —**	$ —	$ —
Other deferred charges and assets/Other deferred credits and liabilities	**1**	**—**	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**$ 3**	**$ —**	$ —	$ —
Gross amounts recognized	**$ 7**	**$ 11**	$ —	$ 47
Gross amounts offset	**$ (3)**	**$ (3)**	$ —	$ —
Net amounts recognized in the Balance Sheets(*)	**$ 4**	**$ 8**	$ —	$ 47

(*) At December 31, 2015, the fair value amounts for derivative contracts subject to netting arrangements were presented gross on the balance sheet.

Energy-related derivatives not designated as hedging instruments were immaterial for 2016 and 2015.

At December 31, 2016 and 2015, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

	Unrealized Losses			**Unrealized Gains**		
Derivative Category	**Balance Sheet Location**	**2016**	2015	**Balance Sheet Location**	**2016**	2015
		(in millions)			*(in millions)*	
Energy-related derivatives:(*)	Other regulatory assets, current	**$ (5)**	$ (29)	Other regulatory liabilities, current	**$ 1**	$ —
	Other regulatory assets, deferred	**(3)**	(18)	Other regulatory liabilities, deferred	**—**	—
Total energy-related derivative gains (losses)		**$ (8)**	$ (47)		**$ 1**	$ —

(*) At December 31, 2016, the unrealized gains and losses for derivative contracts subject to netting arrangements were presented net on the balance sheet. At December 31, 2015, the unrealized gains and losses for derivative contracts were presented gross on the balance sheet.

For all years presented, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of operations were immaterial.

For the year ended December 31, 2016, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of operations were $3 million. For the years ended December 31, 2015 and 2014, these effects were immaterial.

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

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, 2016, the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2016, the fair value of derivative liabilities with contingent features, including 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 because of joint and several liability features underlying these derivatives, was immaterial.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. 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.

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 2016 and 2015 is as follows:

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) After Dividends on Preferred Stock
		(in millions)	
March 2016	**$ 257**	**$ (10)**	**$ 11**
June 2016	**277**	**(28)**	**2**
September 2016	**352**	**9**	**26**
December 2016	**277**	**(166)**	**(89)**
March 2015	$ 276	$ 24	$ 35
June 2015	275	12	49
September 2015	341	(66)	(21)
December 2015	246	(143)	(71)

In accordance with the adoption of ASU 2016-09 (see Note 1 under "Recently Issued Accounting Standards"), previously reported amounts for income tax expense were reduced by $1 million in 2016.

As a result of the revisions to the cost estimate for the Kemper IGCC, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $206 million ($127 million after tax) in the fourth quarter 2016, $88 million ($54 million after tax) in the third quarter 2016, $81 million ($50 million after tax) in the second quarter 2016, $53 million ($33 million after tax) in the first quarter 2016, $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, and $9 million ($6 million after tax) in the first quarter 2015. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

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

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	2016	2015	2014	2013	2012
Operating Revenues (in millions)	**$ 1,163**	$ 1,138	$ 1,243	$ 1,145	$ 1,036
Net Income (Loss) After Dividends on Preferred Stock (in millions)	**$ (50)**	$ (8)	$ (329)	$ (477)	$ 100
Cash Dividends on Common Stock (in millions)	**$ —**	$ —	$ —	$ 72	$ 107
Return on Average Common Equity (percent)	**(1.87)**	(0.34)	(15.43)	(24.28)	7.14
Total Assets (in millions)[(a)(b)]	**$ 8,235**	$ 7,840	$ 6,642	$ 5,822	$ 5,334
Gross Property Additions (in millions)	**$ 946**	$ 972	$ 1,389	$ 1,773	$ 1,665
Capitalization (in millions):					
Common stock equity	**$ 2,943**	$ 2,359	$ 2,084	$ 2,177	$ 1,749
Redeemable preferred stock	**33**	33	33	33	33
Long-term debt[(a)]	**2,424**	1,886	1,621	2,157	1,561
Total (excluding amounts due within one year)	**$ 5,400**	$ 4,278	$ 3,738	$ 4,367	$ 3,343
Capitalization Ratios (percent):					
Common stock equity	**54.5**	55.1	55.8	49.9	52.3
Redeemable preferred stock	**0.6**	0.8	0.9	0.7	1.0
Long-term debt[(a)]	**44.9**	44.1	43.3	49.4	46.7
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**153,172**	153,158	152,453	152,585	152,265
Commercial	**33,783**	33,663	33,496	33,250	33,112
Industrial	**451**	467	482	480	472
Other	**175**	175	175	175	175
Total	**187,581**	187,463	186,606	186,490	186,024
Employees (year-end)	**1,484**	1,478	1,478	1,344	1,281

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $9 million, $11 million, and $4 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $105 million, $16 million, and $36 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

SELECTED FINANCIAL AND OPERATING DATA 2012-2016 (continued)
Mississippi Power Company 2016 Annual Report

	2016	2015	2014	2013	2012
Operating Revenues (in millions):					
Residential	**$ 260**	$ 238	$ 239	$ 242	$ 227
Commercial	**279**	256	257	266	251
Industrial	**313**	287	291	289	263
Other	**7**	(5)	8	2	6
Total retail	**859**	776	795	799	747
Wholesale — non-affiliates	**261**	270	323	294	256
Wholesale — affiliates	**26**	76	107	35	16
Total revenues from sales of electricity	**1,146**	1,122	1,225	1,128	1,019
Other revenues	**17**	16	18	17	17
Total	**$ 1,163**	$ 1,138	$ 1,243	$ 1,145	$ 1,036
Kilowatt-Hour Sales (in millions):					
Residential	**2,051**	2,025	2,126	2,088	2,046
Commercial	**2,842**	2,806	2,860	2,865	2,916
Industrial	**4,906**	4,958	4,943	4,739	4,702
Other	**39**	40	40	40	38
Total retail	**9,838**	9,829	9,969	9,732	9,702
Wholesale — non-affiliates	**3,920**	3,852	4,191	3,929	3,819
Wholesale — affiliates	**1,108**	2,807	2,900	931	572
Total	**14,866**	16,488	17,060	14,592	14,093
Average Revenue Per Kilowatt-Hour (cents)(*):					
Residential	**12.68**	11.75	11.26	11.59	11.09
Commercial	**9.82**	9.12	8.99	9.27	8.60
Industrial	**6.38**	5.79	5.89	6.10	5.59
Total retail	**8.73**	7.90	7.97	8.21	7.70
Wholesale	**5.71**	5.20	6.06	6.76	6.19
Total sales	**7.71**	6.80	7.18	7.73	7.23
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,383**	13,242	13,934	13,680	13,426
Residential Average Annual Revenue Per Customer	**$ 1,697**	$ 1,556	$ 1,568	$ 1,585	$ 1,489
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**3,481**	3,561	3,867	3,088	3,088
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,195**	2,548	2,618	2,083	2,168
Summer	**2,384**	2,403	2,345	2,352	2,435
Annual Load Factor (percent)	**64.0**	60.6	59.4	64.7	61.9
Plant Availability Fossil-Steam (percent)	**91.4**	90.6	87.6	89.3	91.5
Source of Energy Supply (percent):					
Coal	**8.0**	16.5	39.7	32.7	22.8
Oil and gas	**84.9**	81.6	55.3	57.1	63.9
Purchased power —					
From non-affiliates	**(0.3)**	0.4	1.4	2.0	2.0
From affiliates	**7.4**	1.5	3.6	8.2	11.3
Total	**100.0**	100.0	100.0	100.0	100.0

(*) 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
Mississippi Power Company 2016 Annual Report

Directors

Carl J. Chaney
Director and Chief Executive Officer, First NBC Bank Holding Company and First NBC Bank
New Orleans, Louisiana. Elected 2009

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

Thomas A. Dews
President
C. L. Dews & Sons Foundry and Machinery Co., Inc.
Hattiesburg, Mississippi. Elected 2013
(Retired effective 2/1/17)

G. Edison Holland, Jr.
President and Chief Executive Officer Southern Company Holdings, Inc. and Executive Vice President Southern Company Services, Inc.
Atlanta, Georgia. Elected 2013
(Resigned effective 8/4/16)

Mark E. Keenum
President
Mississippi State University
Mississippi State, Mississippi. Elected 2013

Christine L. Pickering
Christy Pickering, CPA Public Accounting Firm
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., Waters Trucks and Tractor Co., Inc., and Waters Transportation, Inc.
Meridian, Mississippi. Elected 2010

Anthony L. Wilson
Chairman, President, and Chief Executive Officer
Mississippi Power Company
Gulfport, Mississippi. Elected 2016

Officers

Anthony L. Wilson
Chairman, President, and Chief Executive Officer
(Elected Chairman effective 8/4/16)

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

A. Nicole Faulk
Vice President of Customer Services Organization

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

R. Allen Reaves
Vice President and Senior Production Officer

Billy F. Thornton
Vice President of External Affairs

Emile J. Troxclair III
Vice President of Kemper Development

Cynthia F. Shaw
Comptroller

Vicki L. Pierce
Corporate Secretary and Assistant Treasurer

Stacy R. Kilcoyne
Vice President
(Resigned effective 3/2/17)

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 electric service to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast. The Company provides electric service to approximately 188,000 customers within its service territory. In 2016, retail energy sales accounted for 66.2% of the Company's total sales of 14.9 billion kilowatt-hours.

The Company is a wholly-owned subsidiary of The Southern Company, which is the parent company of the Company and three other traditional electric operating companies, Southern Power Company, and Southern Company Gas.

Registrar, Transfer Agent, and Dividend Paying Agent
All series of Preferred Stock
Wells Fargo Shareowner Services
P.O. Box 64856
St. Paul, MN 55154-0856
(800) 554-7626

www.shareowneronline.com

Trustee, Registrar, and Interest Paying Agent
All series of Senior Notes
Wells Fargo Bank, N.A.
Corporate, Municipal & Escrow Services
150 East 42nd Street
40th Floor
New York, NY 10017
(917) 260-1534

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. No dividends were declared by the Company to its common stockholder for the past two years.

Number of Preferred Shareholders of record as of December 31, 2016 was 195.

Form 10-K
A copy of the 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.

The Form 10-K, as well as other documents filed by the Company pursuant to the Securities Exchange Act of 1934, as amended, are available electronically at http://www.sec.gov.

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Gulfport, Mississippi 39501
(228) 864-1211

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Atlanta, Georgia 30303

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

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