Gulf Power

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October 12, 2016

VIA ELECTRONIC FILING

Ms. Carlotta Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Petition for an increase in rates by Gulf Power Company, Docket No. 160186-EI

Re: Petition for approval of 2016 depreciation and dismantlement studies, approval of proposed depreciation rates and annual dismantlement accruals and Plant Smith Units 1 and 2 regulatory asset amortization by Gulf Power Company, Docket No. 160170-EI

Dear Ms. Stauffer:

Attached is Gulf Power Company's Minimum Filing Requirements Section F – Miscellaneous Schedules Volume One.

(Document 27 of 29)

Sincerely,

Robert L. McGee, Jr.

Robert L. McGee, Jr.
Regulatory & Pricing Manager

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 160186-EI

Gulf Power

MINIMUM FILING REQUIREMENTS

SECTION F – MISCELLANEOUS SCHEDULES
VOLUME ONE

GULF POWER COMPANY

Docket No. 160186-EI
Minimum Filing Requirements

Index

F. Miscellaneous Schedules
Volume One

Schedule F-1	ANNUAL AND QUARTERLY REPORTS TO SHAREHOLDERS	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 160186-EI	EXPLANATION: Provide a copy of the most recent Annual Report to Shareholders and all subsequent Quarterly Reports. The company shall file all Quarterly and Annual Reports as they become available during the proceeding.	Type of Data Shown: ____ Projected Test Year Ended 12/31/17 ____ Prior Year Ended 12/31/16 X Historical Year Ended 12/31/15 Witness: X. Liu, J. J. Hodnett

Line No.	
1	Gulf Power Company's 2015 Annual Report is attached.

Supporting Schedules: Recap Schedules:

GULF POWER COMPANY

2015 ANNUAL REPORT

GULF POWER

A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2015 Annual Report

The management of Gulf Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (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, 2015.

S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer

Xia Liu
Vice President and Chief Financial Officer

February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2015 and 2014, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2015. 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 29 to 67) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2016

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power, Gulf Power Company, and Mississippi Power

OVERVIEW

Business Activities

Gulf Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, restoration following major storms, and fuel. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. Through 2015, capacity revenues represented the majority of the Company's wholesale earnings. The Company had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 (205 MWs) and these capacity revenues represented 82% of total wholesale capacity revenues for 2015. Due to the expiration of a wholesale contract at the end of 2015 and future expiration dates of the remaining wholesale contracts for the unit, the Company currently has contracts to cover 34% of the unit for 2016 and 27% of the unit through 2019. Although the Company is actively evaluating alternatives relating to this asset, including replacement wholesale contracts, the expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts will have a material negative impact on the Company's earnings in 2016 and may continue to have a material negative impact in future years. In the event some portion of the Company's ownership of Plant Scherer Unit 3 is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the Southern Company power pool or into the wholesale market.

In 2013, the Florida PSC voted to approve the settlement agreement (2013 Rate Case Settlement Agreement) among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million annually effective January 2014 and subsequently increased base rates approximately $20 million annually effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); (3) may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017, of which $28.5 million had been recorded as of December 31, 2015; and (4) is accruing a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Retail Base Rate Case" herein for additional details of the 2013 Rate Case Settlement Agreement.

Key Performance Indicators

The Company continues to focus on several key performance indicators including customer satisfaction, plant availability, system reliability, and net income after dividends on preference 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 of these surveys in measuring performance, which the Company achieved in 2015.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's 2015 Peak Season EFOR of 0.87% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's performance for 2015 was better than the target for these transmission and distribution reliability measures.

The Company uses net income after dividends on preference stock as the primary measure of the Company's financial performance. See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Earnings

The Company's 2015 net income after dividends on preference stock was $148 million, representing an $8 million, or 5.7%, increase over the previous year. The increase was primarily due to an increase in retail base revenues effective January 1, 2015, and a reduction in depreciation, both as authorized in the 2013 Rate Case Settlement Agreement, partially offset by higher operations and maintenance expenses as compared to the corresponding period in 2014.

In 2014, the net income after dividends on preference stock was $140 million, representing a $16 million, or 12.7%, increase over the previous year. The increase was primarily due to higher retail revenues, partially offset by higher other operations and maintenance expenses as compared to the corresponding period in 2013.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2015	**2015**	2014
		(in millions)	
Operating revenues	**$ 1,483**	**$ (107)**	$ 150
Fuel	**445**	**(160)**	72
Purchased power	**135**	**28**	22
Other operations and maintenance	**354**	**13**	31
Depreciation and amortization	**141**	**(4)**	(4)
Taxes other than income taxes	**118**	**7**	13
Total operating expenses	**1,193**	**(116)**	134
Operating income	**290**	**9**	16
Total other income and (expense)	**(41)**	**3**	9
Income taxes	**92**	**4**	8
Net income	**157**	**8**	17
Dividends on preference stock	**9**	**—**	1
Net income after dividends on preference stock	**$ 148**	**$ 8**	$ 16

Operating Revenues

Operating revenues for 2015 were $1.48 billion, reflecting a decrease of $107 million from 2014. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2015	2014
	(in millions)	
Retail — prior year	**$ 1,267**	$ 1,170
Estimated change resulting from –		
Rates and pricing	**22**	47
Sales growth	**—**	8
Weather	**3**	10
Fuel and other cost recovery	**(43)**	32
Retail — current year	**1,249**	1,267
Wholesale revenues –		
Non-affiliates	**107**	129
Affiliates	**58**	130
Total wholesale revenues	**165**	259
Other operating revenues	**69**	64
Total operating revenues	**$ 1,483**	$ 1,590
Percent change	**(6.7)%**	10.4%

In 2015, retail revenues decreased $18 million, or 1.4%, when compared to 2014 primarily as a result of lower fuel cost recovery revenues partially offset by higher revenues associated with purchased power capacity costs and higher revenues resulting from an increase in retail base rates, as authorized in the 2013 Rate Case Settlement Agreement, as well as an increase in the environmental and energy conservation cost recovery clause rates, both effective in January 2015. In 2014, retail revenues increased $97 million, or 8.3%, when compared to 2013 primarily as a result of higher fuel cost recovery revenues and higher revenues resulting from an increase in retail base rates effective January 2014, as authorized in the 2013 Rate Case Settlement Agreement. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

In 2015, revenues associated with changes in rates and pricing included higher revenues due to increases in retail base rates and the Company's environmental and energy conservation cost recovery clauses. In 2014, revenues associated with changes in rates and pricing included higher revenues due to an increase in retail base rates and revenues associated with higher rates under the Company's environmental cost recovery clause. Annually, the Company petitions the Florida PSC for recovery of projected environmental and energy conservation costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate case and cost recovery clauses, including the Company's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

Wholesale revenues from power sales to non-affiliated utilities were as follows:

	2015	2014	2013
		(in millions)	
Capacity and other	**$ 67**	$ 65	$ 64
Energy	**40**	64	45
Total non-affiliated	**$ 107**	$ 129	$ 109

Wholesale revenues from sales to non-affiliates consist of long-term sales agreements to other utilities in Florida and Georgia and short-term opportunity sales. Capacity revenues from long-term sales agreements represent the greatest contribution to net income. The energy is generally sold at variable cost. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy. Wholesale energy revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. See FUTURE EARNINGS POTENTIAL – "General" for additional information regarding the expiration of long-term sales agreements for Plant Scherer Unit 3, which will materially impact future wholesale earnings.

In 2015, wholesale revenues from sales to non-affiliates decreased $22 million, or 17.1%, as compared to the prior year primarily due to a 37.7% decrease in KWH sales resulting from lower sales under the Plant Scherer Unit 3 long-term sales agreements due to a planned outage and lower natural gas market prices that led to increased self-generation from customer-owned units. In 2014, wholesale revenues from sales to non-affiliates increased $20 million, or 18.1%, as compared to the prior year primarily due to a 43.7% increase in KWH sales as a result of lower-priced energy supply alternatives from the Southern Company system's resources and fewer planned outages at Plant Scherer Unit 3 partially offset by a 1.9% decrease in the price of energy sold to non-affiliates due to the lower cost of fuel per KWH generated.

Wholesale revenues from sales to affiliated companies 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 the revenue related to these energy sales generally offsets the cost of energy sold. In 2015, wholesale revenues from sales to affiliates decreased $72 million, or 55.4%, as compared to the prior year primarily due to a 23.5% decrease in the price of energy sold to affiliates due to lower power pool interchange rates resulting from lower natural gas market prices and a 42.0% decrease in KWH sales that resulted from the availability of lower-cost generation alternatives. In 2014, wholesale revenues from sales to affiliates increased $30 million, or 30.7%, as compared to the prior year primarily due to a 24.5% increase in the price of energy sold to affiliates due to higher marginal generation costs and a 5.0% increase in KWH sales as a result of an increase of the Company's generation dispatched to serve affiliated companies' higher weather-related energy demand primarily in the first and third quarters of 2014.

Other operating revenues increased $5 million, or 7.8%, in 2015 as compared to the prior year primarily due to a $2 million increase in franchise fees and a $2 million increase in revenues from other energy services. In 2014, other operating revenues increased $3 million, or 5.5%, as compared to the prior year primarily due to a $5 million increase in franchise fees due to increased retail revenues, partially offset by a $2 million decrease in revenues from other energy services. Franchise fees have no impact on net income. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2015 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2015	**2015**	2014	**2015**	2014
	(in millions)				
Residential	**5,365**	**— %**	5.4%	**(1.0)%**	1.3%
Commercial	**3,898**	**1.6**	0.7	**0.3**	0.1
Industrial	**1,798**	**(2.8)**	8.8	**(2.8)**	8.8
Other	**25**	**(0.1)**	20.5	**(0.1)**	20.5
Total retail	**11,086**	**0.1**	4.3	**(0.8)%**	2.1%
Wholesale					
Non-affiliates	**1,040**	**(37.7)**	43.7		
Affiliates	**1,906**	**(42.0)**	5.0		
Total wholesale	**2,946**	**(40.5)**	15.5		
Total energy sales	**14,032**	**(12.5)%**	7.5%		

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.

Residential KWH sales increased minimally in 2015 compared to 2014 due to customer growth and warmer weather in the second and third quarters of 2015, mostly offset by a decline in use per customer. Residential KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth.

Commercial KWH sales increased in 2015 compared to 2014 due to customer growth and warmer weather in the second and third quarters of 2015, partially offset by a decline in use per customer. Commercial KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth, partially offset by a decline in weather-adjusted use per customer.

Industrial KWH sales decreased in 2015 compared to 2014 primarily due to increased customer co-generation as a result of lower natural gas prices, partially offset by increases due to changes in customers' operations. Industrial KWH sales increased in 2014 compared to 2013 primarily due to decreased customer co-generation and changes in customers' operations.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel, 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:

	2015	2014	2013
Total generation *(millions of KWHs)*	**8,629**	11,109	9,216
Total purchased power *(millions of KWHs)*	**5,976**	5,547	6,298
Sources of generation *(percent)* –			
Coal	**57**	67	61
Gas	**43**	33	39
Cost of fuel, generated *(cents per net KWH)* –			
Coal[(a)]	**3.88**	4.03	4.12
Gas	**4.22**	3.93	3.95
Average cost of fuel, generated *(cents per net KWH)*[(a)]	**4.03**	3.99	4.05
Average cost of purchased power *(cents per net KWH)*[(b)]	**3.89**	4.83	3.88

(a) 2013 cost of coal includes the effect of a payment received pursuant to the resolution of a coal contract dispute.

(b) Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

In 2015, total fuel and purchased power expenses were $580 million, a decrease of $132 million, or 18.5%, from the prior year costs. The decrease was primarily the result of a $79 million decrease due to a lower volume of KWHs generated and purchased due to the availability of lower-cost generation alternatives and a $53 million decrease due to a lower average cost of fuel and purchased power.

In 2014, total fuel and purchased power expenses were $712 million, an increase of $94 million, or 15.2%, from the prior year costs. Total fuel and purchased power expenses for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the higher volume of KWHs generated and purchased increased expenses $55 million primarily due to increased Company owned generation dispatched to serve higher Southern Company system demand as a result of colder weather in the first quarter and warmer weather in the third quarter 2014. The increased expenses also included an $18 million increase due to a higher average cost of fuel and purchased power.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel and purchased power capacity cost recovery clauses and long-term wholesale contracts. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" and " – Purchased Power Capacity Recovery" for additional information.

Fuel

Fuel expense was $445 million in 2015, a decrease of $160 million, or 26.4%, from the prior year costs. The decrease was primarily due to a 22.3% lower volume of KWHs generated due to the availability of lower-cost generation alternatives, partially offset by a 1.0% increase in the average cost of fuel due to higher natural gas prices per KWH generated. In 2014, fuel expense was $605 million, an increase of $72 million, or 13.5%, from the prior year costs. The increase was primarily due to a 20.5% higher volume of KWHs generated to serve higher Southern Company system loads due to colder weather in the first quarter 2014 and warmer weather in the third quarter 2014. The fuel expense for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel per KWH generated decreased 6.8%.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $100 million in 2015, an increase of $18 million, or 22.0%, from the prior year. The increase was primarily due to a $26 million increase in capacity costs associated with a scheduled price increase for an existing PPA, partially offset by the expiration of another PPA, an 11.9% decrease in the average cost per KWH purchased due to lower market prices for fuel, and a 7.8% decrease in the volume of KWHs purchased due to the availability of lower-cost generation alternatives. In 2014, purchased power expense from non-affiliates was $82 million in 2014, an increase of $30 million, or 56.3%, from the prior year. The increase was due to a 37.3% increase in the average cost per KWH purchased, which included a $28 million increase in capacity costs associated with a scheduled price increase for an existing PPA, partially offset by the expiration of another PPA. This increase was partially offset by a 16.3% decrease in the volume of KWHs purchased due to colder regional weather conditions in the first quarter 2014 which limited the availability of market resources.

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

Purchased Power – Affiliates

Purchased power expense from affiliates was $35 million in 2015, an increase of $10 million, or 40.0%, from the prior year. The increase was primarily due to a 108.9% increase in the volume of KWHs purchased primarily due to the availability of lower-cost generation alternatives available from the power pool, partially offset by a 34.2% decrease in the average cost per KWH purchased due to lower power pool interchange rates. In 2014, purchased power expense from affiliates was $25 million, a decrease of $8 million, or 23.1%, from the prior year. The decrease was primarily due to a 43.3% decrease in the average cost per KWH purchased, which included a $14 million reduction in capacity costs primarily associated with the expiration of an existing PPA. This decrease was partially offset by a 33.2% increase in the volume of KWHs purchased primarily due to higher planned outages for the Company's generating units in the fourth quarter 2014.

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

Other Operations and Maintenance Expenses

In 2015, other operations and maintenance expenses increased $13 million, or 3.8%, compared to the prior year primarily due to increases of $6 million in employee compensation and benefits including pension costs, amortization of $3 million of expenses previously incurred in retail base rate cases as authorized in the 2013 Rate Case Settlement Agreement, and $2 million in energy service contracts. In 2014, other operations and maintenance expenses increased $31 million, or 10.1%, compared to the prior year primarily due to increases in routine and planned maintenance expenses at generation, transmission and distribution facilities.

Expenses from energy services did not have a significant impact on earnings since they were generally offset by associated revenues.

Depreciation and Amortization

Depreciation and amortization decreased $4 million, or 2.8%, in 2015 compared to the prior year. As authorized in the 2013 Rate Case Settlement Agreement, the Company recorded an $11.7 million additional reduction in depreciation in 2015 as compared to 2014. This decrease was partially offset by an increase of $8 million primarily attributable to property additions at transmission and distribution facilities. In 2014, depreciation and amortization decreased $4 million, or 2.7%, compared to the prior year. As authorized in the 2013 Rate Case Settlement Agreement, the Company recorded an $8.4 million reduction in depreciation in 2014. This decrease was partially offset by increases of $4 million primarily attributable to property additions at generation, transmission, and distribution facilities. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $7 million, or 6.3%, in 2015 compared to the prior year primarily due to increases of $3 million in property taxes, $2 million in franchise fees and $2 million in gross receipts taxes. In 2014, taxes other than income taxes increased $13 million, or 13.0%, compared to the prior year primarily due to increases of $4 million in franchise fees and $4 million in gross receipts taxes as well as a $3 million increase in property taxes. Gross receipts taxes and franchise fees are based on billed revenues and have no impact on net income. These taxes are collected from customers and remitted to governmental agencies.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $4 million, or 7.5%, in 2015 compared to the prior year primarily due to $6 million in deferred returns on transmission projects, which reduce interest expense and are recorded as a regulatory asset, as authorized in the 2013 Rate Case Settlement Agreement. This decrease was partially offset by a $2 million increase in interest expense related to long-term debt resulting from the issuance of senior notes in 2014. In 2014, interest expense, net of amounts capitalized decreased $3 million, or 5.0%, compared to the prior year primarily due to an increase in capitalization of AFUDC debt related to the construction of environmental control projects and lower interest rates on pollution control bonds, offset by increases in long-term debt resulting from the issuance of additional senior notes in 2014.

Income Taxes

Income taxes increased $4 million, or 4.5%, in 2015 compared to the prior year primarily due to higher pre-tax earnings. In 2014, income taxes increased $8 million, or 10.5%, compared to the prior year primarily due to higher pre-tax earnings. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, the rate of economic growth or decline in the Company's service territory, and the successful remarketing of wholesale capacity as current contracts expire. Demand for electricity is partially 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.

The Company's wholesale business consists of two types of agreements. The first type, referred to as requirements service, provides that the Company serves the customer's capacity and energy requirements from Company resources. The second type, referred to as a unit sale, is a wholesale customer purchase from a dedicated generating plant unit where a portion of that unit is reserved for the customer. These agreements are associated with the Company's ownership of Plant Scherer Unit 3 and consist of both capacity and energy sales. Through 2015, capacity revenues represented the majority of the Company's wholesale earnings. The Company had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 and these capacity revenues represented 82% of total wholesale capacity revenues for 2015. Due to the expiration of a wholesale contract at the end of 2015 and future expiration dates of the remaining wholesale contracts for the unit, the Company currently has contracts to cover 34% of the unit for 2016 and 27% of the unit through 2019. Although the Company is actively evaluating alternatives relating to this asset, including replacement wholesale contracts, the expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts will have a material negative impact on the Company's earnings in 2016 and may continue to have a material negative impact in future years. In the event some portion of the Company's ownership of Plant Scherer Unit 3 is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the Southern Company power pool or into the wholesale market.

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 retail rates or through long-term wholesale agreements on a timely basis or through market-based contracts. The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The Company's current long-term wholesale agreements contain provisions that permit charging the customer with costs incurred as a result of changes in environmental laws and regulations. The full impact of any such regulatory or legislative changes cannot be determined at this time. 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 or long-term wholesale agreements could contribute to reduced demand for electricity as well as impact the cost competitiveness of wholesale capacity, which could negatively affect results of operations, cash flows, and financial condition. See "Other Matters" herein and Note 3 to the financial statements under "Environmental Matters" and "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" for additional information, including a discussion on the State of Florida's statutory provisions on environmental cost recovery.

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 2015, the Company had invested approximately $1.9 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $116 million, $227 million, and $143 million for 2015, 2014, and 2013, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $117 million from 2016 through 2018, with annual totals of approximately $30 million, $43 million, and $44 million for 2016, 2017, and 2018, respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information. The Company also anticipates costs associated with closure in place and ground water monitoring of ash ponds in accordance with the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation (ARO) liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, 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.

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. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. The compliance deadline set by the final MATS rule was April 16, 2015, with provisions for extensions to April 16, 2016. The implementation strategy for the MATS rule includes emission controls, retirements, and fuel conversions to achieve compliance by the deadlines applicable to each Company unit. On June 29, 2015, the U.S. Supreme Court issued a decision finding that in developing the MATS rule the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units. On December 15, 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule to the EPA without vacatur to respond to the U.S. Supreme Court's decision. The EPA's supplemental finding in response to the U.S. Supreme Court's decision, which the EPA proposes to finalize in April 2016, is not expected to have any impact on the MATS rule compliance requirements and deadlines.

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. On October 26, 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 will recommend area designations by October 2016, and the EPA is expected to finalize them by October 2017.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard in December 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred designation decisions for certain areas in Florida.

Final revisions to the NAAQS for sulfur dioxide (SO_2), which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has finalized a data requirements rule to support additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I having begun in 2015 and Phase II beginning in 2017. On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Florida and Georgia, but rejected all other pending challenges to the rule. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. On December 3, 2015, the EPA published a proposed revision to CSAPR that would revise existing ozone-season emissions budgets for nitrogen oxide in Mississippi and would remove Florida from the CSAPR program. The EPA proposes to finalize this rulemaking by summer 2016.

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.

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

On June 12, 2015, the EPA published a final rule requiring certain states (including Florida, Georgia, and Mississippi) to revise or remove the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM) by no later than November 22, 2016.

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. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, CSAPR, regional haze regulations, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. 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.

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 October 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

On November 3, 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 National Pollutant Discharge Elimination System 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. The ultimate impact of these requirements will depend on pending and any future legal challenges, compliance dates, and implementation of the final rule and cannot be determined at this time.

On June 29, 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 August 28, 2015, but on October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The ultimate impact of the final rule will depend on the outcome of this and other pending legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

In addition, numeric nutrient water quality standards promulgated by the State of Florida to limit the amount of nitrogen and phosphorous allowed in state waters are in effect for the State's streams and estuaries. The impact of these standards will depend on further regulatory action in connection with their site-specific implementation through the State of Florida's National Pollutant Discharge Elimination System permitting program and Total Maximum Daily Load restoration program and cannot be determined at this time.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs.

Coal Combustion Residuals

The Company currently manages CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at three electric generating plants in Florida and is a co-owner of units at generating plants located in Mississippi and Georgia operated by Mississippi Power and Georgia Power, respectively. In addition to on-site storage, the Company sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Florida, Georgia, and Mississippi 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.

On April 17, 2015, the EPA published the CCR Rule in the Federal Register, which became effective on October 19, 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. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

Based on initial cost estimates for closure in place and groundwater monitoring of ash ponds pursuant to the CCR Rule, the Company 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, 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. The Company is currently completing an analysis of the plan of closure for all ash ponds, including the timing of closure and related cost recovery through regulated rates subject to Florida PSC approval. Based on the results of that analysis, the Company may accelerate the timing of some ash pond closures which could increase its ARO liabilities from the amounts presently recorded. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. 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, 2015.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company 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. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, these liabilities have no impact to the Company's net income. 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

On October 23, 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 its review with the courts. The stay will remain in effect through the resolution of the litigation, whether resolved in the U.S. Court of Appeals for the District of Columbia Circuit or 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. 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 Company's ongoing review of the final rules; the outcome of legal challenges, including legal challenges filed by the traditional operating companies; individual state implementation of the EPA's final guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

The United Nations 21st international climate change conference took place in late 2015. The result was the adoption of 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 increasing those commitments every five years. The ultimate impact of this agreement depends on its ratification and implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2014 greenhouse gas emissions were approximately 10 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2015 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

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 operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional 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 operating companies and in some adjacent areas. The FERC directed the traditional 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 operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Retail Base Rate Case

In 2013, the Florida PSC voted to approve the 2013 Rate Case Settlement Agreement among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million annually effective January 2014 and subsequently increased base rates approximately $20 million annually effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) is accruing a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.

The 2013 Rate Case Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. For 2015 and 2014, the Company recognized reductions in depreciation expense of $20.1 million and $8.4 million, respectively.

Cost Recovery Clauses

On November 2, 2015, the Florida PSC approved the Company's 2016 annual cost recovery clause rates for its fuel, purchased power capacity, environmental, and energy conservation cost recovery clauses. The net effect of the approved changes is an expected $49 million decrease in annual revenue for 2016. The decreased revenues will not have a significant impact on net income since most of the revenues will be offset by lower expenses.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Note 1 to the financial statements under "Revenues" for additional information.

Renewables

On April 16, 2015, the Florida PSC approved three energy purchase agreements totaling 120 MWs of utility-scale solar generation located at three military installations in northwest Florida. Purchases under these solar agreements are expected to begin by early 2017. On May 5, 2015, the Florida PSC approved an energy purchase agreement for up to 178 MWs of wind generation in central Oklahoma. Purchases under these agreements began in January 2016, are for energy only, and will be recovered through the Company's fuel cost recovery mechanism.

Income Tax Matters

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 2017; 40% bonus depreciation for 2018; and 30% bonus depreciation for 2019 and for certain long-lived assets placed in service in 2020. The extension of 50% bonus depreciation is expected to result in approximately $105 million of positive cash flows for the 2015 tax year and the estimated cash flow benefit of bonus depreciation related to the PATH Act is expected to be approximately $27 million for the 2016 tax year.

Other Matters

On February 6, 2015, the Company announced plans to retire its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016, as a result of the cost to comply with environmental regulations imposed by the EPA. In connection with this retirement, the Company reclassified the net carrying value of these units from plant in service, net of depreciation, to other utility plant, net. The net book value of these units at December 31, 2015 was approximately $62 million. Subsequent to December 31, 2015, the Company filed a petition with the Florida PSC requesting permission to create a regulatory asset for the remaining net book value of Plant Smith Units 1 and 2 and the remaining inventory associated with these units as of the retirement date. The retirement of these units is not expected to have a material impact on the Company's financial statements as the Company expects to recover these amounts through its rates; however, the ultimate outcome depends on future rate proceedings with the Florida PSC and cannot be determined at this time.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, 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.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

The Company is subject to retail regulation by the Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost-based regulation by the FERC with respect to wholesale transmission rates. 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, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

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 the Company's facilities that are subject to the CCR Rule and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the 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.

As a result of the final CCR Rule discussed above, the Company recorded new AROs for facilities that are subject to the CCR Rule. The cost estimates are based on information using various assumptions related to closure in place 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, 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.

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 has 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 will decrease 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 $1 million or less change in total annual benefit expense and a $19 million or less change in projected obligations.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers,* revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances in long-term debt totaling $8 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 9 to the financial statements for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the Company. See Note 2 to the financial statements for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid expenses of $3 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 to the financial statements for disclosures impacted by ASU 2015-17.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2015. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing facilities, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2016 through 2018, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period are primarily to maintain existing generation facilities, to add environmental modifications to existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances in the capital markets, by accessing borrowings from financial institutions, and through equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan decreased in value as of December 31, 2015 as compared to December 31, 2014. No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated during 2016. See Note 2 to the financial statements under "Pension Plans" for additional information.

Net cash provided from operating activities totaled $460 million in 2015, an increase of $116 million from 2014, primarily due to increases in cash flows related to clause recovery and bonus depreciation. This increase was partially offset by decreases related to the timing of fossil fuel stock purchases and vendor payments. Net cash provided from operating activities totaled $344 million in 2014, an increase of $13 million from 2013, primarily due to increases in cash flows related to clause recovery, partially offset by decreases in cash flows associated with voluntary contributions to the qualified pension plan.

Net cash used for investing activities totaled $281 million, $358 million, and $307 million for 2015, 2014, and 2013, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $247 million, $361 million, and $305 million for 2015, 2014, and 2013, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash used for financing activities totaled $144 million in 2015 primarily due to the payment of common stock dividends and redemptions of long-term debt, partially offset by an increase in notes payable and proceeds from the issuance of common stock to Southern Company. Net cash provided from financing activities totaled $31 million in 2014 primarily due to the issuance of long-term debt and common stock, partially offset by the payment of common stock dividends, the redemption of long-term debt and a decrease to notes payable. Net cash used for financing activities totaled $34 million in 2013 primarily due to the payment of common stock dividends and redemptions of long-term debt, partially offset by issuances of stock to Southern Company and issuances of long-term debt. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2015 included increases of $195 million in property, plant, and equipment, primarily due to additions in generation, transmission, and distribution facilities, $110 million in securities due within one year primarily due to senior notes maturing in 2016, $96 million in accumulated deferred income taxes primarily related to bonus depreciation, and $96 million in AROs. Other significant changes include decreases of $169 million in long-term debt and $37 million in under recovered regulatory clause revenues. See Note 1 and Note 5 to the financial statements for additional information regarding AROs and deferred income taxes, respectively.

The Company's ratio of common equity to total capitalization, including short-term debt, was 46.0% in 2015 and 44.7% in 2014. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, external security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

Security issuances are subject to annual regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs, including its commercial paper program which is supported by bank credit facilities.

At December 31, 2015, the Company had approximately $74 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2015 were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2016	**2017**	**2018**	**Total**	**Unused**	**One Year**	**Two Years**	**Term Out**	**No Term Out**
	(in millions)		*(in millions)*		*(in millions)*		*(in millions)*	
$80	$30	$165	$275	$275	$50	$—	$50	$30

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

In November 2015, the Company amended and restated certain of its multi-year credit arrangements which, among other things, extended the maturity dates for the majority of the Company's agreements from 2016 to 2018.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross acceleration provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the Company. Such cross acceleration provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness, the payment of which was then accelerated. The Company is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

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.

Most of the unused credit arrangements with banks are allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2015 was approximately $82 million. In addition, at December 31, 2015, the Company had $33 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

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

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2015:					
Commercial paper	**$ 142**	**0.7%**	**$ 101**	**0.4%**	**$ 175**
Short-term bank debt	**—**	**—%**	**10**	**0.7%**	**40**
Total	**$ 142**	**0.7%**	**$ 111**	**0.4%**	
December 31, 2014:					
Commercial paper	$ 110	0.3 %	$ 85	0.2 %	$ 145
December 31, 2013:					
Commercial paper	$ 136	0.2 %	$ 92	0.2 %	$ 173
Short-term bank debt	—	N/A	11	1.2 %	125
Total	$ 136	0.2 %	$ 103	0.3 %	

(*) Average and maximum amounts are based upon daily balances during the year.

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, short-term bank term loans and operating cash flows.

Financing Activities

In January 2015, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In June 2015, the Company entered into a $40 million aggregate principal amount three-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for credit support, working capital, and other general corporate purposes. The loan was repaid at maturity.

In July 2015, the Company purchased and held $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds (Gulf Power Company Project), Series 2012. These bonds were remarketed to the public on July 16, 2015.

In September 2015, the Company redeemed $60 million aggregate principal amount of its Series L 5.65% Senior Notes due September 1, 2035.

In October 2015, the Company entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $80 million.

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

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, transmission, and energy price risk management.

The maximum potential collateral requirements under these contracts at December 31, 2015 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements	
	(in millions)	
At BBB- and/or Baa3	$	91
Below BBB- and/or Baa3	$	467

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, 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 August 17, 2015, S&P downgraded the consolidated long-term issuer rating of Southern Company (including the Company) to A- from A and revised its credit rating outlook from negative to stable. Separately, on August 24, 2015, S&P revised its credit rating outlook from stable to negative following the announcement of the proposed merger of a wholly-owned direct subsidiary of Southern Company with and into AGL Resources Inc.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $82 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2016 was 0.03%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would not materially affect annualized interest expense at January 1, 2016. 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 fuel and electricity prices, the Company enters into financial hedge contracts for natural gas purchases and physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Florida PSC and the actual cost of fuel is recovered through the retail fuel clause. The Company had no material change in market risk exposure for the year ended December 31, 2015 when compared to the year ended December 31, 2014.

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, substantially all of which are composed of regulatory hedges, were as follows:

		2015 Changes		2014 Changes
		Fair Value		
		(in millions)		
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$**	**(72)**	$	(10)
Contracts realized or settled		**47**		(3)
Current period changes(*)		**(75)**		(59)
Contracts outstanding at the end of the period, assets (liabilities), net	**$**	**(100)**	$	(72)

(*) 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 were 82 million mmBtu and 85 million mmBtu as of December 31, 2015 and December 31, 2014, respectively.

The weighted average swap contract cost above market prices was approximately $1.17 per mmBtu as of December 31, 2015 and $0.80 per mmBtu as of December 31, 2014. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2015 and 2014, 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 fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented and the actual cost of fuel is recovered through the retail fuel 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. 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, 2015 were as follows:

	Fair Value Measurements December 31, 2015			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(100)	(49)	(46)	(5)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (100)	$ (49)	$ (46)	$ (5)

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.

Through 2015, capacity revenues represented the majority of the Company's wholesale earnings. The Company had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 and these capacity revenues represented 82% of total wholesale capacity revenues for 2015. Due to the expiration of a wholesale contract at the end of 2015 and future expiration dates of the remaining wholesale contracts for the unit, the Company currently has contracts to cover 34% of the unit for 2016 and 27% of the unit through 2019. Although the Company is actively evaluating alternatives relating to this asset, including replacement wholesale contracts, the expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts will have a material negative impact on the Company's earnings in 2016 and may continue to have a material negative impact in future years. In the event some portion of the Company's ownership of Plant Scherer Unit 3 is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the Southern Company power pool or into the wholesale market.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $215 million for 2016, $197 million for 2017, and $176 million for 2018. These amounts include capital expenditures related to contractual purchase commitments for capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $30 million, $43 million, and $44 million for 2016, 2017, and 2018, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure in place and ground water monitoring of ash ponds at Plant Scholz and in accordance with the CCR Rule, which are not reflected in the capital expenditures above as these costs are associated with 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, are estimated to be $16 million, $15 million, and $47 million for the years 2016, 2017, and 2018, 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 the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

Contractual Obligations

	2016	2017-2018	2019-2020	After 2020	Total
			(in millions)		
Long-term debt[(a)] –					
Principal	$ 110	$ 85	$ 175	$ 949	$ 1,319
Interest	54	92	87	755	988
Financial derivative obligations[(b)]	49	46	5	—	100
Preference stock dividends[(c)]	9	18	18	—	45
Operating leases[(d)]	10	11	—	—	21
Purchase commitments –					
Capital[(e)]	188	373	—	—	561
Fuel[(f)]	219	287	178	107	791
Purchased power[(g)]	115	234	241	910	1,500
Other[(h)]	14	32	34	156	236
Pension and other postretirement benefit plans[(i)]	5	11	—	—	16
Total	$ 773	$ 1,189	$ 738	$ 2,877	$ 5,577

(a) All amounts are reflected based on final maturity dates. 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, 2016, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

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

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

(d) Excludes a PPA accounted for as a lease and is included in purchased power.

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures associated with environmental regulations. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected in "Other." At December 31, 2015, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(f) 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, 2015.

(g) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity clause. Energy costs associated with PPAs are recovered through the fuel clause. See Notes 3 and 7 to the financial statements for additional information.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices. Limestone costs are recovered through the environmental cost recovery clause. See Note 3 to the financial statements for additional information.

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

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2015 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, 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, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, estimated sales and purchases under power sale and purchase agreements, 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 legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, 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, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including, without limitation, IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the 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 and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards;
- 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;
- 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 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, 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 INCOME
For the Years Ended December 31, 2015, 2014, and 2013
Gulf Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 1,249**	$ 1,267	$ 1,170
Wholesale revenues, non-affiliates	**107**	129	109
Wholesale revenues, affiliates	**58**	130	100
Other revenues	**69**	64	61
Total operating revenues	**1,483**	1,590	1,440
Operating Expenses:			
Fuel	**445**	605	533
Purchased power, non-affiliates	**100**	82	52
Purchased power, affiliates	**35**	25	33
Other operations and maintenance	**354**	341	310
Depreciation and amortization	**141**	145	149
Taxes other than income taxes	**118**	111	98
Total operating expenses	**1,193**	1,309	1,175
Operating Income	**290**	281	265
Other Income and (Expense):			
Allowance for equity funds used during construction	**13**	12	6
Interest expense, net of amounts capitalized	**(49)**	(53)	(56)
Other income (expense), net	**(5)**	(3)	(3)
Total other income and (expense)	**(41)**	(44)	(53)
Earnings Before Income Taxes	**249**	237	212
Income taxes	**92**	88	80
Net Income	**157**	149	132
Dividends on Preference Stock	**9**	9	8
Net Income After Dividends on Preference Stock	**$ 148**	$ 140	$ 124

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2015, 2014, and 2013
Gulf Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Net Income	**$ 157**	$ 149	$ 132
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $-, respectively	**1**	—	—
Reclassification adjustment for amounts included in net income, net of tax of $-, $-, and $-, respectively	—	—	1
Total other comprehensive income (loss)	**1**	—	1
Comprehensive Income	**$ 158**	$ 149	$ 133

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2015, 2014, and 2013
Gulf Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Activities:			
Net income	**$ 157**	$ 149	$ 132
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**152**	153	156
Deferred income taxes	**90**	65	77
Allowance for equity funds used during construction	**(13)**	(12)	(6)
Pension, postretirement, and other employee benefits	**10**	(23)	11
Other, net	**7**	2	9
Changes in certain current assets and liabilities —			
-Receivables	**33**	(17)	(49)
-Fossil fuel stock	**(6)**	34	19
-Prepaid income taxes	**32**	(19)	16
-Other current assets	**(2)**	(2)	(1)
-Accounts payable	**(22)**	8	(7)
-Accrued compensation	**2**	11	(3)
-Over recovered regulatory clause revenues	**22**	—	(17)
-Other current liabilities	**(2)**	(5)	(6)
Net cash provided from operating activities	**460**	344	331
Investing Activities:			
Property additions	**(235)**	(348)	(293)
Cost of removal net of salvage	**(10)**	(13)	(14)
Change in construction payables	**(28)**	12	7
Payments pursuant to long-term service agreements	**(8)**	(8)	(7)
Other investing activities	—	(1)	—
Net cash used for investing activities	**(281)**	(358)	(307)
Financing Activities:			
Increase (decrease) in notes payable, net	**32**	(26)	12
Proceeds —			
Common stock issued to parent	**20**	50	40
Capital contributions from parent company	**4**	4	3
Preference stock	—	—	50
Pollution control revenue bonds	**13**	42	63
Senior notes	—	200	90
Redemptions —			
Pollution control revenue bonds	**(13)**	(29)	(76)
Senior notes	**(60)**	(75)	(90)
Payment of preference stock dividends	**(9)**	(9)	(7)
Payment of common stock dividends	**(130)**	(123)	(115)
Other financing activities	**(1)**	(3)	(4)
Net cash provided from (used for) financing activities	**(144)**	31	(34)
Net Change in Cash and Cash Equivalents	**35**	17	(10)
Cash and Cash Equivalents at Beginning of Year	**39**	22	32
Cash and Cash Equivalents at End of Year	**$ 74**	$ 39	$ 22
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of \$6, \$5, and \$3 capitalized, respectively)	**$ 52**	$ 48	$ 53
Income taxes (net of refunds)	**(7)**	44	(11)
Noncash transactions — accrued property additions at year-end	**20**	42	32

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

BALANCE SHEETS
At December 31, 2015 and 2014
Gulf Power Company 2015 Annual Report

Assets	2015	2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 74**	$ 39
Receivables —		
Customer accounts receivable	**76**	73
Unbilled revenues	**54**	58
Under recovered regulatory clause revenues	**20**	57
Other accounts and notes receivable	**9**	8
Affiliated companies	**1**	10
Accumulated provision for uncollectible accounts	**(1)**	(2)
Income taxes receivable, current	**27**	—
Fossil fuel stock, at average cost	**108**	101
Materials and supplies, at average cost	**56**	56
Other regulatory assets, current	**90**	74
Prepaid expenses	**8**	37
Other current assets	**14**	2
Total current assets	**536**	513
Property, Plant, and Equipment:		
In service	**5,045**	4,495
Less accumulated provision for depreciation	**1,296**	1,296
Plant in service, net of depreciation	**3,749**	3,199
Other utility plant, net	**62**	—
Construction work in progress	**48**	465
Total property, plant, and equipment	**3,859**	3,664
Other Property and Investments	**4**	15
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**61**	56
Other regulatory assets, deferred	**427**	416
Other deferred charges and assets	**33**	33
Total deferred charges and other assets	**521**	505
Total Assets	**$ 4,920**	$ 4,697

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

BALANCE SHEETS
At December 31, 2015 and 2014
Gulf Power Company 2015 Annual Report

Liabilities and Stockholder's Equity		**2015**		2014
		(in millions)		
Current Liabilities:				
Securities due within one year	**$**	**110**	$	—
Notes payable		**142**		110
Accounts payable —				
Affiliated		**55**		87
Other		**44**		56
Customer deposits		**36**		35
Accrued taxes —				
Accrued income taxes		**4**		—
Other accrued taxes		**9**		9
Accrued interest		**9**		11
Accrued compensation		**25**		23
Deferred capacity expense, current		**22**		22
Other regulatory liabilities, current		**22**		1
Liabilities from risk management activities		**49**		37
Other current liabilities		**40**		22
Total current liabilities		**567**		413
Long-Term Debt (See accompanying statements)		**1,193**		1,362
Deferred Credits and Other Liabilities:				
Accumulated deferred income taxes		**893**		797
Employee benefit obligations		**129**		121
Deferred capacity expense		**141**		163
Asset retirement obligations		**113**		17
Other cost of removal obligations		**233**		235
Other regulatory liabilities, deferred		**47**		48
Other deferred credits and liabilities		**102**		85
Total deferred credits and other liabilities		**1,658**		1,466
Total Liabilities		**3,418**		3,241
Preference Stock (See accompanying statements)		**147**		147
Common Stockholder's Equity (See accompanying statements)		**1,355**		1,309
Total Liabilities and Stockholder's Equity	**$**	**4,920**	$	4,697
Commitments and Contingent Matters (See notes)				

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

STATEMENTS OF CAPITALIZATION
At December 31, 2015 and 2014
Gulf Power Company 2015 Annual Report

	2015	2014	**2015**	2014
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
5.30% due 2016	**$ 110**	$ 110		
5.90% due 2017	**85**	85		
4.75% due 2020	**175**	175		
3.10% to 5.75% due 2022-2051	**640**	700		
Total long-term notes payable	**1,010**	1,070		
Other long-term debt —				
Pollution control revenue bonds —				
0.55% to 4.45% due 2022-2049	**227**	240		
Variable rates (0.01% to 0.12% at 1/1/16) due 2022-2042	**82**	69		
Total other long-term debt	**309**	309		
Unamortized debt discount	**(8)**	(9)		
Unamortized debt issuance expense	**(8)**	(8)		
Total long-term debt (annual interest requirement — $54 million)	**1,303**	1,362		
Less amount due within one year	**110**	—		
Long-term debt excluding amount due within one year	**1,193**	1,362	**44.3%**	48.3%
Preferred and Preference Stock:				
Authorized — 20,000,000 shares — preferred stock				
— 10,000,000 shares — preference stock				
Outstanding — $100 par or stated value				
— 6% preference stock — 550,000 shares (non-cumulative)	**54**	54		
— 6.45% preference stock — 450,000 shares (non-cumulative)	**44**	44		
— 5.60% preference stock — 500,000 shares (non-cumulative)	**49**	49		
Total preference stock (annual dividend requirement — $9 million)	**147**	147	**5.4**	5.2
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 2015: 5,642,717 shares				
— 2014: 5,442,717 shares	**503**	483		
Paid-in capital	**567**	560		
Retained earnings	**285**	267		
Accumulated other comprehensive loss	**—**	(1)		
Total common stockholder's equity	**1,355**	1,309	**50.3**	46.5
Total Capitalization	**$ 2,695**	$ 2,818	**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, 2015, 2014, and 2013
Gulf Power Company 2015 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2012	5	$ 393	$ 549	$ 241	$ (2)	$ 1,181
Net income after dividends on preference stock	—	—	—	124	—	124
Issuance of common stock	—	40	—	—	—	40
Capital contributions from parent company	—	—	4	—	—	4
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(115)	—	(115)
Balance at December 31, 2013	5	433	553	250	(1)	1,235
Net income after dividends on preference stock	—	—	—	140	—	140
Issuance of common stock	—	50	—	—	—	50
Capital contributions from parent company	—	—	7	—	—	7
Cash dividends on common stock	—	—	—	(123)	—	(123)
Balance at December 31, 2014	**5**	**483**	**560**	**267**	**(1)**	**1,309**
Net income after dividends on preference stock	**—**	**—**	**—**	**148**	**—**	**148**
Issuance of common stock	**1**	**20**	**—**	**—**	**—**	**20**
Capital contributions from parent company	**—**	**—**	**7**	**—**	**—**	**7**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**1**	**1**
Cash dividends on common stock	**—**	**—**	**—**	**(130)**	**—**	**(130)**
Balance at December 31, 2015	**6**	**$ 503**	**$ 567**	**$ 285**	**$ —**	**$ 1,355**

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

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

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

The equity method is used for entities in which the Company has significant influence but does not control.

The Company is subject to regulation by the FERC and the Florida 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

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers,* revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances in long-term debt totaling $8 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 9 for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the Company. See Note 2 for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid expenses of $3 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 for disclosures impacted by ASU 2015-17.

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 $81 million, $80 million, and $78 million during 2015, 2014, and 2013, 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 operating agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $12 million, $9 million, and $10 million and Mississippi Power $27 million, $31 million, and $17 million in 2015, 2014, and 2013, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company has an agreement with Alabama Power under which Alabama Power has made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA from a combined cycle plant located in Alabama. The transmission improvements were completed in 2014. The Company expects to pay Alabama Power approximately $12 million a year from 2016 through 2023 for these improvements. Payments by the Company to Alabama Power were $14 million, $12 million, and $8 million in 2015, 2014, and 2013, respectively, for the improvements. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2015, 2014, or 2013.

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

Regulatory Assets and Liabilities

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

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

	2015	2014	Note
	(in millions)		
PPA charges	$ **163**	$ 185	(j,k)
Retiree benefit plans, net	**147**	148	(i,j)
Fuel-hedging assets, net	**104**	73	(g,j)
Deferred income tax charges	**59**	53	(a)
Environmental remediation	**46**	48	(h,j)
Regulatory asset, offset to other cost of removal	**29**	8	(m)
Closure of Plant Scholz ash pond	**29**	—	(h,j)
Loss on reacquired debt	**15**	16	(c)
Vacation pay	**10**	10	(d,j)
Deferred return on transmission upgrades	**10**	—	(m)
Other regulatory assets, net	**7**	9	(l)
Deferred income tax charges — Medicare subsidy	**2**	3	(b)
Under recovered regulatory clause revenues	**1**	53	(e)
Other cost of removal obligations	**(262)**	(243)	(a)
Property damage reserve	**(38)**	(35)	(f)
Over recovered regulatory clause revenues	**(22)**	—	(e)
Deferred income tax credits	**(3)**	(4)	(a)
Asset retirement obligations, net	**(1)**	(5)	(a,j)
Total regulatory assets (liabilities), net	$ **296**	$ 319	

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

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered and amortized over periods not exceeding 14 years.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years.

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

(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.

(f) Recorded and recovered or amortized as approved by the Florida PSC.

(g) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed five years. Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clause.

(h) Recovered through the environmental cost recovery clause when the remediation or the work is performed.

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

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

(k) Recovered over the life of the PPA for periods up to eight years.

(l) Comprised primarily of net book value of retired meters and recovery of injuries and damages costs. These costs are recorded and recovered or amortized as approved by the Florida PSC, generally over periods not exceeding eight years.

(m) Recorded as authorized by the Florida PSC in the settlement agreement approved in December 2013 (2013 Rate Case Settlement Agreement). See Note 3 for additional information.

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

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida 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. Federal ITCs utilized are deferred and amortized to income over the average life of the related property and state ITCs are recognized in the period in which the credit is claimed on the state income tax return. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

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.

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

	2015	2014
	(in millions)	
Generation	**$ 2,974**	$ 2,638
Transmission	**691**	516
Distribution	**1,196**	1,157
General	**182**	182
Plant acquisition adjustment	**2**	2
Total plant in service	**$ 5,045**	$ 4,495

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 as incurred or performed.

On February 6, 2015, the Company announced plans to retire its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016, as a result of the cost to comply with environmental regulations imposed by the EPA. In connection with this retirement, the Company reclassified the net carrying value of these units from plant in service, net of depreciation, to other utility plant, net. The net book value of these units at December 31, 2015 was approximately $62 million.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.5% in 2015 and 3.6% in both 2014 and 2013. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. As authorized by the Florida PSC in the 2013 Rate Case Settlement Agreement, the Company is allowed to reduce depreciation and record a regulatory asset in an aggregate amount up to $62.5 million between January 2014 and June 2017. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) 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 an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability 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 on April 17, 2015 (CCR Rule), principally ash ponds, and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the 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 Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

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

	2015	2014
	(in millions)	
Balance at beginning of year	**$ 17**	$ 16
Liabilities incurred	**105**	—
Liabilities settled	**(1)**	—
Accretion	**2**	1
Cash flow revisions	**7**	—
Balance at end of year	**$ 130**	$ 17

The increase in liabilities incurred in 2015 is primarily related to AROs associated with the portion of the Company's steam generation facilities impacted by the CCR Rule. The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2015 using various assumptions related to closure in place 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, 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.

In connection with permitting activity related to the coal ash pond at the retired Plant Scholz facility, the Company recorded additional AROs of $29 million.

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 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 calculating taxable income. The average annual AFUDC rate was 5.73% for both 2015 and 2014 and 6.26% for 2013. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 10.80%, 10.93%, and 6.87% for 2015, 2014, and 2013, respectively.

Impairment of Long-Lived Assets and Intangibles

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

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $48 million and $55 million. The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2015, 2014, and 2013. As of December 31, 2015 and 2014, the balance in the Company's property damage reserve totaled approximately $38 million and $35 million, respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. As authorized in the 2013 Rate Case Settlement Agreement, the Company may recover costs associated with any tropical systems named by the National Hurricane Center through the initiation of a storm surcharge. The storm surcharge will begin, on an interim basis, 60 days following the filing of a cost recovery petition. The storm surcharge generally may not exceed $4.00/1,000 KWHs on monthly residential bills in aggregate for a calendar year. This limitation does not apply if the Company incurs in excess of $100 million in storm recovery costs that qualify for recovery in a given calendar year. This threshold amount is inclusive of the amount necessary to replenish the storm reserve to the level that existed as of December 31, 2013. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional details of the 2013 Rate Case Settlement Agreement.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was zero at December 31, 2015 and had a balance of $4.0 million at December 31, 2014. Included in current liabilities and deferred credits and other liabilities in the balance sheets at December 31, 2014 is $1.6 million and $2.4 million, respectively. The Company recorded a liability with a corresponding regulatory asset of $1.7 million for estimated liabilities related to outstanding claims and suits in excess of the reserve balance at December 31, 2015, of which $1.6 million and $0.1 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. There were no liabilities in excess of the reserve balance at December 31, 2014.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of oil, natural gas, coal, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. 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, and electricity purchases and sales. 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 fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts 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 income. 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.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2015.

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

Comprehensive Income

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

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2016. 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, 2016, 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:	2015	2014	2013
Pension plans			
Discount rate – interest costs	**4.18%**	5.02%	4.27%
Discount rate – service costs	**4.48**	5.02	4.27
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**3.59**	3.59	3.59
Other postretirement benefit plans			
Discount rate – interest costs	**4.04%**	4.86%	4.06%
Discount rate – service costs	**4.38**	4.86	4.06
Expected long-term return on plan assets	**8.07**	8.08	8.04
Annual salary increase	**3.59**	3.59	3.59

Assumptions used to determine benefit obligations:	2015	2014
Pension plans		
Discount rate	**4.71%**	4.18%
Annual salary increase	**4.46**	3.59
Other postretirement benefit plans		
Discount rate	**4.51%**	4.04%
Annual salary increase	**4.46**	3.59

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

For purposes of its December 31, 2015 measurement date, the Company adopted new mortality tables for its pension and other postretirement benefit plans, which reflect decreased life expectancies in the U.S. The adoption of new mortality tables reduced the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $9 million and $1 million, respectively.

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, 2015 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2024
Post-65 medical	5.50	4.50	2024
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, 2015 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 4	$ (3)
Service and interest costs	—	—

Pension Plans

The total accumulated benefit obligation for the pension plans was $424 million at December 31, 2015 and $438 million at December 31, 2014. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 491**	$ 395
Service cost	**12**	10
Interest cost	**20**	19
Benefits paid	**(20)**	(16)
Actuarial loss (gain)	**(23)**	83
Balance at end of year	**480**	491
Change in plan assets		
Fair value of plan assets at beginning of year	**435**	386
Actual return on plan assets	**4**	34
Employer contributions	**1**	31
Benefits paid	**(20)**	(16)
Fair value of plan assets at end of year	**420**	435
Accrued liability	**$ (60)**	$ (56)

At December 31, 2015, the projected benefit obligations for the qualified and non-qualified pension plans were $457 million and $23 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's pension plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 142**	$ 146
Current liabilities, other	**(1)**	(1)
Employee benefit obligations	**(59)**	(55)

Presented below are the amounts included in regulatory assets at December 31, 2015 and 2014 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 2016.

	2015	2014	Estimated Amortization in 2016
		(in millions)	
Prior service cost	**$ 2**	$ 3	**$ 1**
Net loss	**140**	143	**6**
Regulatory assets	**$ 142**	$ 146	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 146**	$ 75
Net (gain) loss	**6**	77
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	(1)
Amortization of net gain (loss)	**(9)**	(5)
Total reclassification adjustments	**(10)**	(6)
Total change	**(4)**	71
Ending balance	**$ 142**	$ 146

Components of net periodic pension cost were as follows:

	2015	2014	2013
		(in millions)	
Service cost	**$ 12**	$ 10	$ 11
Interest cost	**20**	19	17
Expected return on plan assets	**(32)**	(28)	(26)
Recognized net loss	**9**	5	9
Net amortization	**1**	1	1
Net periodic pension cost	**$ 10**	$ 7	$ 12

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, 2015, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2016	$ 19
2017	20
2018	21
2019	22
2020	24
2021 to 2025	139

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 78**	$ 69
Service cost	**1**	1
Interest cost	**3**	3
Benefits paid	**(4)**	(4)
Actuarial loss (gain)	**(1)**	11
Plan amendment	**4**	(2)
Retiree drug subsidy	**—**	—
Balance at end of year	**81**	78
Change in plan assets		
Fair value of plan assets at beginning of year	**18**	17
Actual return on plan assets	**—**	2
Employer contributions	**3**	3
Benefits paid	**(4)**	(4)
Fair value of plan assets at end of year	**17**	18
Accrued liability	**$ (64)**	$ (60)

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's other postretirement benefit plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 10**	$ 6
Current liabilities, other	**(1)**	(1)
Other regulatory liabilities, deferred	**(5)**	(4)
Employee benefit obligations	**(63)**	(59)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2015 and 2014 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2016.

	2015	2014	Estimated Amortization in 2016
		(in millions)	
Prior service cost	$ —	$ (2)	$ —
Net loss	5	4	—
Net regulatory assets (liabilities)	$ 5	$ 2	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	$ 2	$ (7)
Net (gain) loss	1	11
Change in prior service costs	2	(2)
Reclassification adjustments:		
Amortization of prior service costs	—	—
Amortization of net gain (loss)	—	—
Total reclassification adjustments	—	—
Total change	3	9
Ending balance	$ 5	$ 2

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

	2015	2014	2013
		(in millions)	
Service cost	$ 1	$ 1	$ 1
Interest cost	3	3	3
Expected return on plan assets	(1)	(1)	(1)
Net amortization	—	—	—
Net periodic postretirement benefit cost	$ 3	$ 3	$ 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)	
2016	$ 5	$ —	$ 5
2017	5	—	5
2018	6	—	6
2019	6	(1)	5
2020	6	(1)	5
2021 to 2025	29	(3)	26

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. 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, 2015 and 2014, along with the targeted mix of assets for each plan, is presented below:

	Target	**2015**	2014
Pension plan assets:			
Domestic equity	26%	**30%**	30%
International equity	25	**23**	23
Fixed income	23	**23**	27
Special situations	3	**2**	1
Real estate investments	14	**16**	14
Private equity	9	**6**	5
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	25%	**29%**	29%
International equity	24	**22**	22
Domestic fixed income	25	**25**	29
Special situations	3	**2**	1
Real estate investments	14	**16**	14
Private equity	9	**6**	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, 2015 and 2014. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

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

The fair values of pension plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 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*	$ 73	$ 31	$ —	$ —	$ 104
International equity*	54	45	—	—	99
Fixed income:					
U.S. Treasury, government, and agency bonds	—	21	—	—	21
Mortgage- and asset-backed securities	—	9	—	—	9
Corporate bonds	—	51	—	—	51
Pooled funds	—	23	—	—	23
Cash equivalents and other	—	7	—	—	7
Real estate investments	14	—	—	55	69
Private equity	—	—	—	29	29
Total	$ 141	$ 187	$ —	$ 84	$ 412

* 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, 2014:	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*	$ 77	$ 32	$ —	$ —	$ 109
International equity*	48	44	—	—	92
Fixed income:					
U.S. Treasury, government, and agency bonds	—	31	—	—	31
Mortgage- and asset-backed securities	—	8	—	—	8
Corporate bonds	—	51	—	—	51
Pooled funds	—	23	—	—	23
Cash equivalents and other	—	30	—	—	30
Real estate investments	13	—	—	50	63
Private equity	—	—	—	26	26
Total	$ 138	$ 219	$ —	$ 76	$ 433

* 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, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 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	—	1	—	—	1
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	1	—	—	—	1
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$ 7	$ 7	$ —	$ 3	$ 17

* 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, 2014:	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*	$ 3	$ 1	$ —	$ —	$ 4
International equity*	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	1	—	—	1
Mortgage- and asset-backed securities	—	1	—	—	1
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	—	1	—	—	1
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$ 6	$ 9	$ —	$ 3	$ 18

* 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 2015, 2014, and 2013 were $4 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 received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2015, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $46 million, of which approximately $4 million is included in under recovered regulatory clause revenues and other current liabilities and approximately $42 million is included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

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

FERC Matters

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 operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional 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 operating companies and in some adjacent areas. The FERC directed the traditional 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 operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

In 2013, the Florida PSC voted to approve the 2013 Rate Case Settlement Agreement among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million annually effective January 2014 and subsequently increased base rates approximately $20 million annually effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) is accruing a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.

The 2013 Rate Case Settlement Agreement also includes a self-executing adjustment mechanism that will increase the authorized retail ROE midpoint and range by 25 basis points in the event the 30-year treasury yield rate increases by an average of at least 75 basis points above 3.7947% for a consecutive six-month period.

The 2013 Rate Case Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. For 2015 and 2014, the Company recognized reductions in depreciation expense of $20.1 million and $8.4 million, respectively.

Pursuant to the 2013 Rate Case Settlement Agreement, the Company may not request an increase in its retail base rates to be effective until after June 2017, unless the Company's actual retail ROE falls below the authorized ROE range.

Cost Recovery Clauses

On November 2, 2015, the Florida PSC approved the Company's annual rate clause request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2016. The net effect of the approved changes is an expected $49 million decrease in annual revenue for 2016. The decreased revenues will not have a significant impact on net income since most of the revenues will be offset by lower expenses.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested.

At December 31, 2015, the over recovered fuel balance was approximately $18 million, which is included in other regulatory liabilities, current in the balance sheets. At December 31, 2014, the under recovered fuel balance was approximately $40 million, which is included in under recovered regulatory clause revenues in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2015 and 2014, the under recovered purchased power capacity balance was immaterial.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2015, the under recovered environmental balance was immaterial. At December 31, 2014, the under recovered environmental balance was approximately $10 million, which is included in under recovered regulatory clause revenues in the balance sheets.

In 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in November 2015. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The total cost of the project was approximately $653 million, with the Company's portion being approximately $316 million, excluding AFUDC. The Company's portion of the cost is being recovered through the environmental cost recovery clause.

Energy Conservation Cost Recovery

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

At December 31, 2015, the over recovered ECCR balance was approximately $4 million, which is included in other regulatory liabilities, current in the balance sheet. At December 31, 2014, the under recovered ECCR balance was approximately $3 million, which is included in under recovered regulatory clause revenues in the balance sheet.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 MWs capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

At December 31, 2015, the Company's percentage ownership and investment in these jointly-owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	**Plant Daniel Units 1 & 2 (coal)**
	(in millions)	
Plant in service	$ 395	$ 669
Accumulated depreciation	136	184
Construction work in progress	2	9
Company Ownership	25%	50%

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

5. INCOME TAXES

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:

	2015	2014	2013
		(in millions)	
Federal -			
Current	**$ (3)**	$ 23	$ 5
Deferred	**80**	52	63
	77	75	68
State -			
Current	**5**	—	(2)
Deferred	**10**	13	14
	15	13	12
Total	**$ 92**	$ 88	$ 80

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:

	2015	2014
	(in millions)	
Deferred tax liabilities-		
Accelerated depreciation	**$ 812**	$ 777
Property basis differences	**133**	52
Fuel recovery clause	**—**	16
Pension and other employee benefits	**39**	34
Regulatory assets associated with employee benefit obligations	**59**	60
Regulatory assets associated with asset retirement obligations	**40**	7
Other	**26**	22
Total	**1,109**	968
Deferred tax assets-		
Federal effect of state deferred taxes	**33**	31
Postretirement benefits	**26**	18
Pension and other employee benefits	**65**	66
Property reserve	**15**	13
Asset retirement obligations	**40**	7
Alternative minimum tax carryforward	**18**	18
Other	**19**	18
Total	**216**	171
Accumulated deferred income taxes	**$ 893**	$ 797

On November 20, 2015, the FASB issued ASU 2015-17, which simplifies the presentation of deferred income taxes. The new guidance resulted in a reclassification from prepaid expenses of $3 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. See Note 1 under "Recently Issued Accounting Standards" for additional information.

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation in 2015 and 2014.

At December 31, 2015, tax-related regulatory assets to be recovered from customers were $61 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, 2015, the tax-related regulatory liabilities to be credited to customers were $3 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 average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to approximately $1 million annually for 2015, 2014, and 2013. At December 31, 2015, all ITCs available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

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

	2015	2014	2013
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.9**	3.5	3.5
Non-deductible book depreciation	**0.5**	0.4	0.5
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.1)	(0.2)
AFUDC equity	**(1.8)**	(1.8)	(1.1)
Other, net	**(0.6)**	0.1	(0.1)
Effective income tax rate	**36.9%**	37.1%	37.6%

Unrecognized Tax Benefits

The Company has no material unrecognized tax benefits for 2015 or 2014. The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial and the Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances, but an estimate of the range of reasonably possible outcomes cannot be determined at this time.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 and 2014 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.

6. FINANCING

Securities Due Within One Year

At December 31, 2015, the Company had $110 million of long-term debt due within one year.

Maturities from 2017 through 2020 applicable to total long-term debt are as follows: $85 million in 2017 and $175 million in 2020. There are no scheduled maturities in 2018 or 2019.

Senior Notes

At each of December 31, 2015 and 2014, the Company had a total of $1.01 billion and $1.07 billion of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totaled approximately $41 million at both December 31, 2015 and 2014.

In September 2015, the Company redeemed $60 million aggregate principal amount of Series L 5.65% Senior Notes due September 1, 2035.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2015 and 2014 was $309 million.

In July 2015, the Company purchased and held $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds (Gulf Power Company Project), Series 2012. The Company remarketed these bonds to the public on July 16, 2015.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2015. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, certain series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2015, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an aggregate outstanding principal amount of $41 million as of December 31, 2015. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At December 31, 2015, committed credit arrangements with banks were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2016	2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)			(in millions)		(in millions)		(in millions)	
$ 80	$ 30	$ 165	$ 275	$ 275	$ 50	$ —	$ 50	$ 30

In November 2015, the Company amended and restated certain of its multi-year credit arrangements which, among other things, extended the maturity dates for the majority of the Company's agreements from 2016 to 2018.

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than $^1/_4$ of 1% for the Company.

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.

Most of these bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2015, the Company was in compliance with these covenants.

Most of the $275 million of unused credit arrangements with banks provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2015 was approximately $82 million. In addition, at December 31, 2015, the Company had $33 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Commercial Paper at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2015	**$ 142**	**0.7%**
December 31, 2014	$ 110	0.3%

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 2015, 2014, and 2013, the Company incurred fuel expense of $445 million, $605 million, and $533 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.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under purchased power agreements accounted for as operating leases was $75 million, $50 million, and $21 million for 2015, 2014, and 2013, respectively.

Estimated total minimum long-term commitments at December 31, 2015 were as follows:

	Operating Lease PPAs
	(in millions)
2016	$ 79
2017	79
2018	79
2019	79
2020	79
2021 and thereafter	191
Total	$ 586

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 operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the operating lease PPAs discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $14 million, $15 million, and $18 million for 2015, 2014, and 2013, respectively.

Estimated total minimum lease payments under these operating leases at December 31, 2015 were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2016	$ 9	$ 1	$ 10
2017	6	1	7
2018	4	—	4
Total	$ 19	$ 2	$ 21

The Company and Mississippi Power jointly entered into an operating lease agreement for aluminum railcars for the transportation of coal to 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 and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, was $2 million in 2015, and $3 million in both 2014 and 2013. The Company's annual railcar lease payments for 2016 and 2017 will average approximately $1 million each year. There are no lease payment obligations for the period 2018 and thereafter.

In addition to railcar leases, the Company has operating lease agreements for barges and towboats for the transport of coal to Plants Crist and Smith. The Company has the option to renew the leases at the end of the lease term. The Company's lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, were $10 million in both 2015 and 2014 and $12 million in 2013. The Company's annual barge and towboat payments for 2016 through 2018 will average approximately $5 million each year.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation, in the form of Southern Company stock options and 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, 2015, there were 198 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. As a result, stock-based compensation granted to employees in 2015 consisted exclusively of performance share units.

For the years ended December 31, 2014 and 2013, employees of the Company were granted stock options for 432,371 shares and 285,209 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014 and 2013 derived using the Black-Scholes stock option pricing model was $2.20 and $2.93, respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented. As of December 31, 2015, 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, 2015, 2014, and 2013 was $2 million, $5 million, and $2 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1 million, $2 million, and $1 million for the years ended December 31, 2015, 2014, and 2013, respectively. As of December 31, 2015, the aggregate intrinsic value for the options outstanding and options exercisable was $7 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 which equates to the requisite service period for accounting purposes. 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, issued in 2015, 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, 2015, 2014, and 2013, employees of the Company were granted performance share units of 48,962, 37,829, and 30,627, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2015, 2014, and 2013, 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 $46.38, $37.54, and $40.50, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2015 was $47.75.

For the years ended December 31, 2015, 2014, and 2013, total compensation cost for performance share units recognized in income was $2 million, $1 million, and $1 million, respectively. The related tax benefit also recognized in income was $1 million in 2015 and immaterial in 2014 and 2013. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2015, there was $2 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 19 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, 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:				
Interest rate derivatives	$ —	$ 1	$ —	$ 1
Cash equivalents	18	—	—	18
Total	$ 18	$ 1	$ —	$ 19
Liabilities:				
Energy-related derivatives	$ —	$ 100	$ —	$ 100

As of December 31, 2014, 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, 2014:	**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	$ 18	$ —	$ —	$ 18
Liabilities:				
Energy-related derivatives	$ —	$ 72	$ —	$ 72

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflect the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2015 and 2014, 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:		
2015	**$ 1,303**	**$ 1,339**
2014	$ 1,362	$ 1,477

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 available 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 may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. 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 commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

Energy-related derivative contracts are accounted for under one of two methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2015, the net volume of energy-related derivative contracts for natural gas positions totaled 82 million mmBtu for the Company, with the longest hedge date of 2020 over which it 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 earnings.

At December 31, 2015, the following interest rate derivative was outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2015
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$ 80	3-month LIBOR	2.32%	December 2026	$ 1

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2016 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2026.

Derivative Financial Statement Presentation and Amounts

At December 31, 2015 and 2014, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ —**	$ —	Liabilities from risk management activities	**$ 49**	$ 37
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**51**	35
Total derivatives designated as hedging instruments for regulatory purposes		**$ —**	$ —		**$ 100**	$ 72
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	**$ 1**	$ —	Liabilities from risk management activities	**$ —**	$ —
Total		**$ 1**	$ —		**$ 100**	$ 72

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2015 and 2014.

The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. At December 31, 2015 and 2014, energy-related derivatives and interest rate derivatives presented in the tables above do not have amounts available for offset.

At December 31, 2015 and 2014, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (49)**	$ (37)	Other regulatory liabilities, current	**$ —**	$ —
	Other regulatory assets, deferred	**(51)**	(35)	Other regulatory liabilities, deferred	**—**	—
Total energy-related derivative gains (losses)		**$ (100)**	$ (72)		**$ —**	$ —

For the years ended December 31, 2015, 2014, and 2013, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2015**	2014	2013	**Statements of Income Location**	**2015**	2014	2013
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ 1**	$ —	$ —	Interest expense, net of amounts capitalized	**$ (1)**	$ (1)	$ (1)

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

For the years ended December 31, 2015, 2014, and 2013, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2015, the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2015, the fair value of derivative liabilities with contingent features was $22 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $52 million and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. 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 2015 and 2014 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in millions)	
March 2015	**$ 357**	**$ 72**	**$ 37**
June 2015	**384**	**69**	**35**
September 2015	**429**	**91**	**48**
December 2015	**313**	**58**	**28**
March 2014	$ 407	$ 74	$ 37
June 2014	384	69	34
September 2014	438	88	46
December 2014	361	50	23

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

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SELECTED FINANCIAL AND OPERATING DATA 2011-2015
Gulf Power Company 2015 Annual Report

		2015		2014		2013		2012		2011
Operating Revenues (in millions)	**$**	**1,483**	$	1,590	$	1,440	$	1,440	$	1,520
Net Income After Dividends on Preference Stock (in millions)	**$**	**148**	$	140	$	124	$	126	$	105
Cash Dividends on Common Stock (in millions)	**$**	**130**	$	123	$	115	$	116	$	110
Return on Average Common Equity (percent)		**11.11**		11.02		10.30		10.92		9.55
Total Assets (in millions)[(a)(b)]	**$**	**4,920**	$	4,697	$	4,321	$	4,167	$	3,858
Gross Property Additions (in millions)	**$**	**247**	$	361	$	305	$	325	$	338
Capitalization (in millions):										
Common stock equity	**$**	**1,355**	$	1,309	$	1,235	$	1,181	$	1,125
Preference stock		**147**		147		147		98		98
Long-term debt[(a)]		**1,193**		1,362		1,150		1,178		1,226
Total (excluding amounts due within one year)	**$**	**2,695**	$	2,818	$	2,532	$	2,457	$	2,449
Capitalization Ratios (percent):										
Common stock equity		**50.3**		46.5		48.8		48.1		45.9
Preference stock		**5.4**		5.2		5.8		4.0		4.0
Long-term debt[(a)]		**44.3**		48.3		45.4		47.9		50.1
Total (excluding amounts due within one year)		**100.0**		100.0		100.0		100.0		100.0
Customers (year-end):										
Residential		**393,149**		388,292		383,980		379,922		378,248
Commercial		**55,460**		54,892		54,567		53,808		53,450
Industrial		**248**		260		260		264		273
Other		**614**		603		582		577		565
Total		**449,471**		444,047		439,389		434,571		432,536
Employees (year-end)		**1,391**		1,384		1,410		1,416		1,424

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $8 million, $8 million, $8 million, and $9 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-03. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(b) A reclassification of deferred tax assets from Total Assets of $3 million, $8 million, $2 million, and $5 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-17. See Note 1 under "Recently Issued Accounting Standards" for additional information.

SELECTED FINANCIAL AND OPERATING DATA 2011-2015 (continued)
Gulf Power Company 2015 Annual Report

	2015	2014	2013	2012	2011
Operating Revenues (in millions):					
Residential	**$ 698**	$ 700	$ 632	$ 609	$ 637
Commercial	**403**	408	395	390	408
Industrial	**144**	153	139	140	158
Other	**4**	6	4	5	5
Total retail	**1,249**	1,267	1,170	1,144	1,208
Wholesale — non-affiliates	**107**	129	109	107	134
Wholesale — affiliates	**58**	130	100	124	111
Total revenues from sales of electricity	**1,414**	1,526	1,379	1,375	1,453
Other revenues	**69**	64	61	65	67
Total	**$ 1,483**	$ 1,590	$ 1,440	$ 1,440	$ 1,520
Kilowatt-Hour Sales (in millions):					
Residential	**5,365**	5,362	5,089	5,054	5,305
Commercial	**3,898**	3,838	3,810	3,859	3,911
Industrial	**1,798**	1,849	1,700	1,725	1,799
Other	**25**	26	21	25	25
Total retail	**11,086**	11,075	10,620	10,663	11,040
Wholesale — non-affiliates	**1,040**	1,670	1,163	977	2,013
Wholesale — affiliates	**1,906**	3,284	3,127	4,370	2,608
Total	**14,032**	16,029	14,910	16,010	15,661
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**13.01**	13.06	12.43	12.06	12.01
Commercial	**10.34**	10.64	10.37	10.11	10.44
Industrial	**8.01**	8.28	8.15	8.14	8.80
Total retail	**11.27**	11.44	11.02	10.73	10.95
Wholesale	**5.60**	5.23	4.87	4.31	5.30
Total sales	**10.08**	9.52	9.25	8.59	9.28
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,705**	13,865	13,301	13,303	14,028
Residential Average Annual Revenue Per Customer	**$ 1,783**	$ 1,811	$ 1,653	$ 1,604	$ 1,685
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,583**	2,663	2,663	2,663	2,663
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,488**	2,684	1,729	2,130	2,485
Summer	**2,491**	2,424	2,356	2,344	2,527
Annual Load Factor (percent)	**54.9**	51.1	55.9	56.3	54.5
Plant Availability Fossil-Steam (percent)*	**88.3**	89.4	92.8	82.5	84.7
Source of Energy Supply (percent):					
Coal	**33.5**	44.5	36.4	34.6	49.4
Gas	**25.6**	22.2	23.0	23.5	24.0
Purchased power —					
From non-affiliates	**30.4**	28.9	37.0	40.2	22.3
From affiliates	**10.5**	4.4	3.6	1.7	4.3
Total	**100.0**	100.0	100.0	100.0	100.0

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

DIRECTORS AND OFFICERS
Gulf Power Company 2015 Annual Report

DIRECTORS

S. W. Connally, Jr.
Chairman, President, and
Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 2012

Allan G. Bense
Panama City businessman and
Partner in several companies
Panama City, Florida. Elected 2010

Deborah H. Calder
Executive Vice President
Navy Federal Credit Union
Pensacola, Florida. Elected 2010

William C. Cramer, Jr.
President
Bill Cramer Chevrolet Cadillac
Buick GMC, Inc.
Panama City, Florida. Elected 2002

Julian B. MacQueen
Founder and Chief Executive Officer
Innisfree Hotels, Inc.
Gulf Breeze, Florida. Elected 2013

J. Mort O'Sullivan, III
Managing Member
Gulf Coast Division of
Warren Averett, LLC
Pensacola, Florida. Elected 2010

Michael T. Rehwinkel
Former Executive Chairman
EVRAZ North America
Pensacola, Florida. Elected 2013

Winston E. Scott
Senior Vice President for External Relations and
Economic Development
Florida Institute of Technology
Melbourne, Florida. Elected 2003

OFFICERS

S. W. Connally, Jr.
Chairman, President, and
Chief Executive Officer
27 Years of Service

Michael L. Burroughs
Vice President – Senior Production Officer
24 Years of Service

Jim R. Fletcher
Vice President – External Affairs and
Corporate Services
30 Years of Service

Xia Liu (1)
Vice President and Chief Financial Officer
18 Years of Service

Wendell E. Smith
Vice President – Power Delivery
32 Years of Service

Richard S. Teel (2)
Vice President and Chief Financial Officer
16 Years of Service

Bentina C. Terry
Vice President – Customer Service and Sales
14 Years of Service

Janet J. Hodnett
Comptroller
35 Years of Service

Chris B. Stadler
Assistant Comptroller
15 Years of Service

Paul D. Trippe
Assistant Comptroller
26 Years of Service

Susan D. Ritenour
Secretary and Treasurer
34 Years of Service

Terry A. Davis (3)
Assistant Secretary and Assistant Treasurer
29 Years of Service

DIRECTORS AND OFFICERS
Gulf Power Company 2015 Annual Report

Sharon A. Jordan (4)
Assistant Secretary
10 Years of Service

Josh J. Mason (5)
Assistant Treasurer
8 Years of Service

Stacy R. Kilcoyne
Vice President
38 Years of Service

Melissa K. Caen
Assistant Secretary and Assistant Treasurer
9 Years of Service

(1) Effective June 1, 2015.
(2) Transferred to an affiliate effective May 31, 2015.
(3) Retired effective June 30, 2015.
(4) Effective May 18, 2015.
(5) Effective May 18, 2015.

CORPORATE INFORMATION
Gulf Power Company 2015 Annual Report

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

Profile
The Company produces and delivers electricity as an integrated utility to both retail and wholesale customers within the State of Florida. The Company sells electricity to approximately 450,000 customers within its service area in the Florida panhandle. In 2015, retail energy sales accounted for 79 percent of the Company's total sales of 14 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of four traditional operating companies, a wholesale generation subsidiary, and other direct and indirect subsidiaries. There is no established public trading market for the Company's common stock.

Registrar, Transfer Agent, and Dividend Paying Agent
Preference Stock
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.
150 East 42nd Street, 40th Floor
New York, NY 10017

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

Quarter	2015	2014
	(in thousands)	
First	**$32,540**	**$30,800**
Second	**32,540**	**30,800**
Third	**32,540**	**30,800**
Fourth	**32,540**	**30,800**

All of the outstanding shares of the Company's preference stock are registered in the name of Cede & Co., as nominee for The Depository Trust Company.

Form 10-K
A copy of Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary at the mailing address below:

Corporate Office
Principal Address & Deliveries:
Gulf Power Company
500 Bayfront Parkway
Pensacola, FL 32520
(850) 444-6111

Mailing Address:
Gulf Power Company
One Energy Place
Pensacola, FL 32520

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

Legal Counsel
Beggs & Lane
A Registered Limited Liability Partnership
P.O. Box 12950
Pensacola, FL 32591

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Schedule F-2	SEC REPORTS	Page 1 of 2
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: Provide a copy of the most recent Form 10-K annual report to the Securities and Exchange Commission and all Form 10-Q quarterly reports filed subsequent to the filing of the latest 10-K.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		______ Projected Test Year Ended 12/31/17
		______ Prior Year Ended 12/31/16
		__X__ Historical Year Ended 12/31/15
DOCKET NO.: 160186-EI		Witness: X. Liu, J. J. Hodnett

Line No.	
1	See Annual Report Attached

Supporting Schedules: Recap Schedules:

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

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2015

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to

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

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

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is listed on the New York Stock Exchange.

Title of each class	Registrant
Common Stock, $5 par value	**The Southern Company**
Junior Subordinated Notes, $25 denominations 6.25% Series 2015A due 2075	
Class A preferred stock, cumulative, $25 stated capital 5.83% Series	**Alabama Power Company**
Class A preferred stock, non-cumulative, Par value $25 per share 6 1/8% Series	**Georgia Power Company**
Senior Notes 5.75% Series 2011A due 2051	**Gulf Power Company**
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value 5.25% Series	**Mississippi Power Company**

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

Title of each class			Registrant
Preferred stock, cumulative, $100 par value			**Alabama Power Company**
4.20% Series	4.60% Series	4.72% Series	
4.52% Series	4.64% Series	4.92% Series	
Preferred stock, cumulative, $100 par value			**Mississippi Power Company**
4.40% Series	4.60% Series		
4.72% Series			

1 As of December 31, 2015.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
The Southern Company	X	
Alabama Power Company	X	
Georgia Power Company	X	
Gulf Power Company		X
Mississippi Power Company		X
Southern Power Company	X	

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒ (Response applicable to all registrants.)

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

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

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

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

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2015: $38.1 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at January 31, 2016
The Southern Company	Par Value $5 Per Share	912,846,995
Alabama Power Company	Par Value $40 Per Share	30,537,500
Georgia Power Company	Without Par Value	9,261,500
Gulf Power Company	Without Par Value	5,642,717
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2016 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statements on Schedule 14C of Alabama Power Company, Georgia Power Company, and Mississippi Power Company relating to each of their respective 2016 Annual Meetings of Shareholders are incorporated by reference into PART III.

Southern Power Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instructions I(2)(b), (c), and (d) of Form 10-K.

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

Table of Contents

DEFINITIONS

When used in Items 1 through 5 and Items 9A through 15, the following terms will have the meanings indicated.

Term	Meaning
AGL Resources	AGL Resources Inc.
Alabama Power	Alabama Power Company
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
Bridge Agreement	Senior unsecured Bridge Credit Agreement, dated as of September 30, 2015, among Southern Company, the lenders identified therein, and Citibank, N.A.
Clean Air Act	Clean Air Act Amendments of 1990
CCR	Coal combustion residuals
Contractor	Westinghouse and its affiliate, WECTEC Global Project Services Inc. (formerly known as CB&I Stone & Webster, Inc.), formerly a subsidiary of The Shaw Group Inc. and Chicago Bridge & Iron Company N.V.
CO_2	Carbon dioxide
CPCN	Certificate of Public Convenience and Necessity
CWIP	Construction Work in Progress
Dalton	City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners
DOE	U.S. Department of Energy
Duke Energy Florida	Duke Energy Florida, Inc.
EMC	Electric membership corporation
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FMPA	Florida Municipal Power Agency
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IBEW	International Brotherhood of Electrical Workers
IGCC	Integrated coal gasification combined cycle
IIC	Intercompany Interchange Contract
Internal Revenue Code	Internal Revenue Code of 1986, as amended
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction by Mississippi Power in Kemper County, Mississippi
KUA	Kissimmee Utility Authority
KW	Kilowatt
KWH	Kilowatt-hour
MATS rule	Mercury and Air Toxics Standards rule
MEAG Power	Municipal Electric Authority of Georgia
Merger	The merger of Merger Sub with and into AGL Resources on the terms and subject to the conditions set forth in the Merger Agreement, with AGL Resources continuing as the surviving corporation and a wholly-owned, direct subsidiary of Southern Company
Merger Agreement	Agreement and Plan of Merger, dated as of August 23, 2015, among Southern Company, AGL Resources, and Merger Sub
Merger Sub	AMS Corp., a wholly-owned, direct subsidiary of Southern Company

DEFINITIONS
(continued)

Term	Meaning
Mirror CWIP	A regulatory liability account for use in mitigating future rate impacts for Mississippi Power customers
Mississippi Power	Mississippi Power Company
MW	Megawatt
NRC	U.S. Nuclear Regulatory Commission
NYSE	New York Stock Exchange
OPC	Oglethorpe Power Corporation
OUC	Orlando Utilities Commission
PATH Act	Protecting Americans from Tax Hikes Act
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Georgia Power's Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PowerSouth	PowerSouth Energy Cooperative
PPA	Power Purchase Agreement
PSC	Public Service Commission
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company
RUS	Rural Utilities Service
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
TIPA	Tax Increase Prevention Act of 2014
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
Vogtle Owners	Georgia Power, OPC, MEAG, and Dalton
Westinghouse	Westinghouse Electric Company LLC

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, the potential financing of the Merger, the expected timing of the completion of the Merger, the strategic goals for the wholesale business, economic recovery, 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 , postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of acquisitions, construction projects, and changing fuel sources, 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, 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 legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws regulating emissions, discharges, and disposal to air, water, and land , and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including , without limitation, Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the 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 and construction 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, 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 any 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 Southern Company's employee and retiree benefit plans and the Southern Company system's nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;
- 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;

- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the expected timing, likelihood, and benefits of completion of the Merger, including the failure to receive, on a timely basis or otherwise, the required approvals by government or regulatory agencies (including the terms of such approvals), the possibility that long-term financing for the Merger may not be put in place prior to the closing, the risk that a condition to closing of the Merger or funding of the Bridge Agreement may not be satisfied, the possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected, the possibility that costs related to the integration of Southern Company and AGL Resources will be greater than expected, the credit ratings of the combined company or its subsidiaries may be different from what the parties expect, the ability to retain and hire key personnel and maintain relationships with customers, suppliers, or other business partners, the diversion of management time on Merger-related issues, and the impact of legislative, regulatory, and competitive changes;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system'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 Southern Company's and any of its subsidiaries' 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 currency exchange rates, counterparty performance, and the economy in general , as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's subsidiaries to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the registrants from time to time with the SEC.

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

PART I

Item 1. BUSINESS

Southern Company was incorporated under the laws of Delaware on November 9, 1945. Southern Company is registered and qualified to do business under the laws of Georgia and is qualified to do business as a foreign corporation under the laws of Alabama. Southern Company owns all of the outstanding common stock of Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, each of which is an operating public utility company. The traditional operating companies supply electric service in the states of Alabama, Georgia, Florida, and Mississippi. More particular information relating to each of the traditional operating companies is as follows:

Alabama Power is a corporation organized under the laws of the State of Alabama on November 10, 1927, by the consolidation of a predecessor Alabama Power Company, Gulf Electric Company, and Houston Power Company. The predecessor Alabama Power Company had been in continuous existence since its incorporation in 1906.

Georgia Power was incorporated under the laws of the State of Georgia on June 26, 1930 and was admitted to do business in Alabama on September 15, 1948 and in Florida on October 13, 1997.

Gulf Power is a Florida corporation that has had a continuous existence since it was originally organized under the laws of the State of Maine on November 2, 1925. Gulf Power was admitted to do business in Florida on January 15, 1926, in Mississippi on October 25, 1976, and in Georgia on November 20, 1984. Gulf Power became a Florida corporation after being domesticated under the laws of the State of Florida on November 2, 2005.

Mississippi Power was incorporated under the laws of the State of Mississippi on July 12, 1972, was admitted to do business in Alabama on November 28, 1972, and effective December 21, 1972, by the merger into it of the predecessor Mississippi Power Company, succeeded to the business and properties of the latter company. The predecessor Mississippi Power Company was incorporated under the laws of the State of Maine on November 24, 1924 and was admitted to do business in Mississippi on December 23, 1924 and in Alabama on December 7, 1962.

In addition, Southern Company owns all of the common stock of Southern Power Company, which is also an operating public utility company. 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 Power Company is a corporation organized under the laws of Delaware on January 8, 2001. Together with its subsidiaries, Southern Power is admitted to do business in the States of Alabama, California, Florida, Georgia, Mississippi, Nevada, New Mexico, North Carolina, Oklahoma, South Carolina, and Texas.

Southern Company also owns all of the outstanding common stock or membership interests of SouthernLINC Wireless, Southern Nuclear, SCS, Southern Holdings, and other direct and indirect subsidiaries. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets these services to the public and also provides wholesale fiber optic solutions to telecommunication providers in the Southeast. Southern Nuclear operates and provides services to Alabama Power's and Georgia Power's nuclear plants and is currently developing Plant Vogtle Units 3 and 4, which are co-owned by Georgia Power. SCS is the Southern Company system service company providing, at cost, specialized services to Southern Company and its subsidiary companies. Southern Holdings is an intermediate holding subsidiary, primarily for Southern Company's investments in leveraged leases and also for energy services.

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,019,680 KWs at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO's capacity and energy. Alabama Power acts as SEGCO's agent in the operation of SEGCO's units and furnishes fuel to SEGCO for its units. SEGCO also owns one 230,000 volt transmission line extending from Plant Gaston to the Georgia state line at which point connection is made with the Georgia Power transmission line system.

On August 23, 2015, Southern Company entered into the Merger Agreement to acquire AGL Resources. Under the terms of the Merger Agreement, subject to the satisfaction or waiver (if permissible under applicable law) of specified conditions, Merger Sub will be merged with and into AGL Resources. AGL Resources will survive the Merger and become a wholly-owned, direct subsidiary of Southern Company. Upon the consummation of the Merger, each share of common stock of AGL Resources issued and outstanding immediately prior to the effective time of the Merger, other than shares owned by AGL Resources as treasury stock, shares owned by a subsidiary of AGL Resources, and any shares owned by shareholders who have properly exercised and perfected dissenters' rights, will be converted into the right to receive $66 in cash, without interest and less any applicable withholding taxes. Other equity-based securities of AGL Resources will be cancelled for cash consideration or converted into new awards from Southern Company as described in the Merger Agreement. See Note 12 to the financial statements under "Southern Company – Proposed Merger with AGL Resources" in Item 8 herein for additional information regarding the Merger.

Southern Company's segment information is included in Note 13 to the financial statements of Southern Company in Item 8 herein.

The registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports are made available on Southern Company's website, free of charge, as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Southern Company's internet address is www.southerncompany.com.

The Southern Company System

Traditional Operating Companies

The traditional operating companies are vertically integrated utilities that own generation, transmission, and distribution facilities. See PROPERTIES in Item 2 herein for additional information on the traditional operating companies' generating facilities. Each company's transmission facilities are connected to the respective company's own generating plants and other sources of power (including certain generating plants owned by Southern Power) and are interconnected with the transmission facilities of the other traditional operating companies and SEGCO. For information on the State of Georgia's integrated transmission system, see "Territory Served by the Traditional Operating Companies and Southern Power" herein.

Agreements in effect with principal neighboring utility systems provide for capacity and energy transactions that may be entered into from time to time for reasons related to reliability or economics. Additionally, the traditional operating companies have entered into voluntary reliability agreements with the subsidiaries of Entergy Corporation, Florida Electric Power Coordinating Group, and Tennessee Valley Authority and with Duke Energy Progress, Inc., Duke Energy Carolinas, LLC, South Carolina Electric & Gas Company, and Virginia Electric and Power Company, each of which provides for the establishment and periodic review of principles and procedures for planning and operation of generation and transmission facilities, maintenance schedules, load retention programs, emergency operations, and other matters affecting the reliability of bulk power supply. The traditional operating companies have joined with other utilities in the Southeast (including some of those referred to above) to form the SERC to augment further the reliability and adequacy of bulk power supply. Through the SERC, the traditional operating companies are represented on the National Electric Reliability Council.

The utility assets of the traditional operating companies and certain utility assets of Southern Power Company are operated as a single integrated electric system, or power pool, pursuant to the IIC. Activities under the IIC are administered by SCS, which acts as agent for the traditional operating companies and Southern Power Company. The fundamental purpose of the power pool is to provide for the coordinated operation of the electric facilities in an effort to achieve the maximum possible economies consistent with the highest practicable reliability of service. Subject to service requirements and other operating limitations, system resources are committed and controlled through the application of centralized economic dispatch. Under the IIC, each traditional operating company and Southern Power Company retains its lowest cost energy resources for the benefit of its own customers and delivers any excess energy to the power pool for use in serving customers of other traditional operating companies or Southern Power Company or for sale by the power pool to third parties. The IIC provides for the recovery of specified costs associated with the affiliated operations thereunder, as well as the proportionate sharing of costs and revenues resulting from power pool transactions with third parties.

Southern Company, each traditional operating company, Southern Power, Southern Nuclear, SEGCO, and other subsidiaries have contracted with SCS to furnish, at direct or allocated cost and upon request, the following services: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communication, and other services with respect to business and operations, construction management, and power pool transactions. Southern Power and SouthernLINC Wireless have also secured from the traditional operating companies certain services which are furnished at cost and, in the case of Southern Power, which are subject to FERC regulations.

Alabama Power and Georgia Power each have a contract with Southern Nuclear to operate the Southern Company system's existing nuclear plants, Plants Farley, Hatch, and Vogtle. In addition, Georgia Power has a contract with Southern Nuclear to develop, license, construct, and operate Plant Vogtle Units 3 and 4. See "Regulation – Nuclear Regulation" herein for additional information.

Southern Power

The term "Southern Power" when used herein refers to Southern Power Company and its subsidiaries while the term "Southern Power Company" when used herein refers only to the parent company. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates (under authority from the FERC) in the wholesale market. Southern Power continually seeks opportunities to execute its strategy to create value through various transactions, including acquisitions and sales of assets, construction of new power plants, and entry into PPAs primarily with investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load serving entities. Southern Power's business activities are not subject to traditional state regulation like the traditional operating companies, but the majority of its business activities are subject to regulation by the FERC. Southern Power has attempted to insulate itself from significant fuel supply, fuel transportation, and electric transmission risks by generally making such risks the responsibility of the counterparties to its PPAs. However, Southern Power's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets, as well as Southern Power’s ability to execute its growth strategy and to construct generating facilities. For additional information on Southern Power's business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Business Activities" of Southern Power in Item 7 herein.

Southern Power Company owns and manages generation assets primarily in the Southeast, which are included in the power pool, and has other wholly-owned subsidiaries, two of which are Southern Renewable Energy, Inc. (SRE) and Southern Renewable Partnerships, LLC (SRP), which were created to own and operate renewable projects either wholly or in partnership with third parties, such as Turner Renewable Energy, LLC (TRE), First Solar Inc. (First Solar), or Recurrent Energy, a subsidiary of Canadian Solar Inc. (Recurrent), which are not included in the power pool. In addition, Southern Power Company has other subsidiaries either with natural gas and biomass generating facilities or pursuing additional natural gas generation and other development opportunities.

Since 2010, SRE and TRE, through Southern Turner Renewable Energy, LLC (STR), a jointly-owned subsidiary owned 90% by SRE, has acquired all of the outstanding membership interests of eight solar projects that own the following solar photovoltaic facilities: Adobe, Apex, Campo Verde, Cimarron, Granville, Macho Springs, Morelos, and Spectrum. In December 2015, STR entered into a purchase agreement with Solar Frontier Americas Holding LLC, the developer of the Calipatria solar project, to acquire all of the outstanding membership interests of Calipatria Solar, LLC (Calipatria), which closed on February 11, 2016. Additionally, in December 2015, SRE acquired 100% of all the outstanding membership interests of Kay Wind, LLC, which owns and operates the Kay Wind facility. In September 2015, SRE entered into a purchase agreement with Apex Clean Energy Holdings, LLC, the developer of the Grant Wind project, to acquire all of the outstanding membership interests of Grant Wind, LLC (Grant Wind), which is expected to close in March 2016 when the project reaches commercial operation.

In 2014 and 2015, SRP acquired 100% of the outstanding class A membership interests of seven partnership entities that own the following solar photovoltaic facilities: Desert Stateline (which is being completed in eight phases), Garland, Imperial Valley, Lost Hills Blackwell, North Star, Roserock, and Tranquillity. Imperial Valley was placed in service in 2014; Lost Hills Blackwell, North Star, and three of the eight phases of Desert Stateline were placed in service in 2015; and phases four and five of Desert Stateline were placed in service in January and February 2016, respectively. Garland, Roserock, Tranquillity, and the remaining three phases of Desert Stateline are expected to be placed in service later in 2016. SRP is entitled to 51% of all cash distributions from the partnership entities and the respective partner who holds the class B membership interests (either First Solar or Recurrent) is entitled to 49% of all cash distributions. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to the seven partnership entities.

In December 2014, Southern Power announced that it will build an approximately 146-MW solar photovoltaic facility, Sandhills, in Taylor County, Georgia. During the first half of 2015, Southern Power Company acquired all of the outstanding membership interests of five entities that were subsequently merged with Southern Power Company for the construction of five solar photovoltaic facilities in Georgia as follows: Decatur County, Decatur Parkway, Butler, Butler Solar Farm, and Pawpaw. Decatur County and Decatur Parkway were placed in service in late 2015; Butler Solar Farm was placed in service in February 2016; and Pawpaw, Sandhills, and Butler are expected to be placed in service during 2016.

The entire output of each of the renewable facilities is contracted under long-term PPAs as shown below in the table of PPAs as of December 31, 2015. See Item 2 – Properties, Note 2 to the financial statements of Southern Power in Item 8 herein, and Note 12 to the financial statements of Southern Company under "Southern Power" in Item 8 herein for additional information regarding Southern Power's acquisitions and construction projects.

As of December 31, 2015, Southern Power had 9,595 MWs of nameplate capacity in commercial operation (including 2,110 MWs owned by its subsidiaries), after taking into consideration its equity ownership percentage of the solar facilities. With the inclusion of the PPAs and capacity associated with the solar facilities currently under construction and the acquisitions of Calipatria and Grant Wind, all as discussed above, as well as other capacity and energy contracts, Southern Power has an average of 75% of its available demonstrated capacity covered for the next five years (through 2020) and an average of 70% of its available demonstrated capacity covered for the next 10 years (through 2025).

Southern Power’s natural gas and biomass sales are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. Southern Power typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that Southern Power serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Southern Power resources not dedicated to serve unit or block sales. Southern Power has rights to purchase power provided by the requirements customers' resources when economically viable.

Southern Power's solar and wind sales are also through long-term PPAs, but do not have a capacity charge. Instead the customers purchase the entire energy output of a dedicated renewable facility through an energy charge.

The following tables set forth Southern Power's existing PPAs as of December 31, 2015:

Block Sales PPAs

Facility/Source	Counterparty	MWs	Contract Term
Addison Unit 1	MEAG Power	152	through April 2029
Addison Units 2 and 4	Georgia Power	293	through May 2030
Addison Unit 3	Georgia Energy Cooperative	151	through May 2030
Cleveland County Unit 1	NCEMC(1)	45-180	through Dec. 2036
Cleveland County Unit 2	NCEMC(1)	180	through Dec. 2036
Cleveland County Unit 3	NCMPA1(2)	183	through Dec. 2031
Dahlberg Units 1, 3, and 5	Cobb EMC	224	Jan. 2016 – Dec. 2025
Dahlberg Units 2, 6, 8, and 10	Georgia Power	298	through May 2025
Dahlberg Unit 4	Georgia Power	73	through May 2030
Franklin Unit 1	Duke Energy Florida, Inc.	350	through May 2016
Franklin Unit 1	Duke Energy Florida, Inc.	434	June 2016 – May 2021
Franklin Unit 2	Morgan Stanley Capital Group	250	Jan. 2016 – Dec. 2025
Franklin Unit 2	Jackson EMC	60-65	Jan. 2016 – Dec. 2035
Franklin Unit 2	GreyStone Power Corporation	35-40	Jan. 2016 – Dec. 2035
Franklin Unit 2	Cobb EMC	100	Jan. 2016 – Dec. 2025
Franklin Unit 3	Exelon Generation Company LLC	100	Jan. 2016 - Dec. 2016
Franklin Unit 3	Cargill Power Markets LLC	50	Jan. 2016 - Dec. 2016
Harris Unit 1	Georgia Power	638	through May 2030
Harris Unit 2	Georgia Power	631	through May 2019
Harris Unit 2	AMEA(3)	25	Jan. 2020 – Dec. 2025
Nacogdoches	City of Austin, Texas	100	through May 2032
NCEMC PPA(4)	EnergyUnited	100	through Dec. 2021
Oleander Units 2, 3, and 4	Seminole Electric Cooperative	155	through May 2021
Oleander Unit 5	FMPA	157	through Dec. 2027
Rowan CT Unit 1	NCMPA1(2)	150	through Dec. 2030
Rowan CT Unit 3	EnergyUnited	113	through Dec. 2023
Rowan CC Unit 4	EnergyUnited	0-328	through Dec. 2025
Rowan CC Unit 4	Duke Energy Progress, Inc.	150	through Dec. 2019
Rowan CC Unit 4	PJM Auction(5)	200	June 2016 – May 2017
Stanton Unit A	OUC	341	through Sept. 2033
Stanton Unit A	FMPA	85	through Sept. 2033
Wansley Unit 6	Georgia Power	570	through May 2017

(1) North Carolina Electric Membership Corporation (NCEMC)

(2) North Carolina Municipal Power Agency 1 (NCMPA1)

(3) Alabama Municipal Electric Authority (AMEA). AMEA will be served by Plant Franklin Unit 1 from January 2018 through December 2019.

(4) Represents sale of power purchased from NCEMC under a PPA.

(5) Pennsylvania, Jersey, Maryland Power Pool

Requirements Services PPAs

Counterparty	MWs		Contract Term
Nine Georgia EMCs	223-456	(1)	through Dec. 2024
Sawnee EMC	116-559	(1)	through Dec. 2027
Cobb EMC	0-316	(1)	Jan. 2016 - Dec. 2025
Flint EMC	128-257	(1)	through Dec. 2024
City of Dalton, Georgia	—	(1)	through Dec. 2017
EnergyUnited	0-219	(1)	through Dec. 2025

(1) Represents a range of forecasted incremental capacity needs over the contract term.

Solar/Wind PPAs

Facility	Counterparty	MWs(1)	Contract Term
Solar			
Adobe(2)	Southern California Edison Company	20	through May 2034
Apex(2)	Nevada Power Company	20	through Dec. 2037
Butler	Georgia Power	100	Dec. 2016 - Dec. 2046 (5)
Butler Solar Farm	Georgia Power	20	Jan. 2016 - Dec. 2035
Calipatria(2)	San Diego Gas & Electric Company	20	Feb. 2016 - Jan. 2036
Campo Verde(2)	San Diego Gas & Electric Company	139	through Sept. 2033
Cimarron(2)	Tri-State Generation and Transmission Association, Inc.	30	through Nov. 2035
Decatur County	Georgia Power	19	through Dec. 2035
Decatur Parkway	Georgia Power	80	through Dec. 2040
Desert Stateline(4)	Southern California Edison Company	300	Sep. 2016 - Oct. 2036 (5)
Garland(4)	Southern California Edison Company	20	Dec. 2016 - Nov. 2036 (5)
Garland(4)	Southern California Edison Company	180	Dec. 2016 - Nov. 2031 (5)
Granville(2)	Duke Energy Progress, Inc.	2.5	through Nov. 2032
Imperial Valley(4)	San Diego Gas & Electric Company	150	through Dec. 2039
Lost Hills Blackwell(4)	City of Roseville & Pacific Gas & Electric Company	32	through Dec. 2043
Macho Springs(2)	El Paso Energy	50	through May 2034
Morelos(2)	Pacific Gas & Electric Company	15	Jan. 2016 - Jan. 2035
North Star(4)	Pacific Gas & Electric Company	60	through May 2035
Pawpaw	Georgia Power	30	Mar. 2016 - Feb. 2046 (5)
Roserock(4)	Austin Energy	157	Oct. 2016 - Sept. 2036 (5)
Sandhills	Cobb EMC	111	Nov. 2016 - Dec. 2041 (5)
Sandhills	Flint EMC	15	Nov. 2016 - Dec. 2041 (5)
Sandhills	Sawnee EMC	15	Nov. 2016 - Dec. 2041 (5)
Sandhills	Middle GA and Irwin EMC	2	Nov. 2016 - Dec. 2041 (5)
Spectrum(2)	Nevada Power Company	30	through Dec. 2038
Tranquillity(4)	Shell Energy North America (US), LP	204	Oct. 2016 - Nov. 2019 (5)
Tranquillity(4)	Southern California Edison Company	204	Dec. 2019 - Nov. 2034 (5)

Facility	Counterparty	MWs(1)	Contract Term
Wind			
Grant Wind(3)	East Texas Electric Cooperative	50	Mar. 2016 - Mar. 2036 (5)
Grant Wind(3)	Northeast Texas Electric Cooperative	50	Mar. 2016 - Mar. 2036 (5)
Grant Wind(3)	Western Farmers Electric Cooperative	50	Mar. 2016 - Mar. 2036 (5)
Kay Wind	Westar	199	Oct. 2016 - Nov. 2036
Kay Wind	Grand River Dam Authority	100	through Dec. 2035

(1) MWs shown are for 100% of the PPA.
(2) Southern Power's equity interest in these facilities is 90%.
(3) Southern Power has entered into an agreement to acquire this facility, which is subject to satisfaction of certain conditions to closing.
(4) Southern Power's equity interest in these facilities is 51%.
(5) Subject to commercial operation.

Purchased Power

Facility/Source	Counterparty	MWs	Contract Term
NCEMC	NCEMC	100	through Dec. 2021

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" and "Acquisitions" of Southern Power in Item 7 herein and Note 2 to the financial statements of Southern Power in Item 8 herein for additional information.

For the year ended December 31, 2015, Southern Power's revenues were derived approximately 15.8% from Georgia Power and approximately 10.7% from Florida Power & Light Company. Southern Power actively pursues replacement PPAs prior to the expiration of its current PPAs and anticipates that the revenues attributable to one customer may be replaced by revenues from a new customer; however, the expiration of any of Southern Power's current PPAs without the successful remarketing of a replacement PPA could have a material negative impact on Southern Power's earnings but is not expected to have a material impact on Southern Company's earnings.

Other Businesses

Southern Holdings is an intermediate holding subsidiary, primarily for Southern Company's investments in leveraged leases and also for energy services.

SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public. SouthernLINC Wireless delivers multiple wireless communication options including push to talk, cellular service, text messaging, wireless internet access, and wireless data. Its system covers approximately 127,000 square miles in the Southeast. SouthernLINC Wireless also provides fiber cable services within the Southeast through its subsidiary, Southern Telecom, Inc.

These efforts to invest in and develop new business opportunities offer potential returns exceeding those of rate-regulated operations. However, these activities also involve a higher degree of risk.

Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2016 through 2018, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company, each traditional operating company, and Southern Power in Item 7 herein. The Southern Company system's construction program consists of capital investment and capital expenditures to comply with environmental statutes and regulations. The Southern Company system also anticipates costs associated with closure in place or by other methods and ground water monitoring of ash ponds in accordance with the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are not reflected in the capital expenditures below as these costs are associated with asset retirement obligation liabilities. In 2016, the construction program is expected to be apportioned approximately as follows:

	Southern Company system [(a)]	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
New Generation	$ 1,224	$ 56	$ 553	$ 3	$ 612
Environmental Compliance [(b)]	683	319	313	30	21
Generation Maintenance	978	293	538	75	72
Transmission	618	167	402	23	26
Distribution	802	285	417	62	37
Nuclear Fuel	230	93	137	—	—
General Plant	307	93	174	22	19
	4,842	1,306	2,534	215	787
Southern Power [(c)]	2,386				
Other subsidiaries	102				
Total	$ 7,330	$ 1,306	$ 2,534	$ 215	$ 787

(a) These amounts include the amounts for the traditional operating companies (as detailed in the table above) as well as the amounts for Southern Power and the other subsidiaries. See "Other Businesses" herein for additional information.

(b) Reflects cost estimates for environmental regulations. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units or costs associated with closure in place or by other methods and ground water monitoring of ash ponds in accordance with the CCR Rule. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company and each traditional operating company in Item 7 herein for additional information.

(c) Includes approximately $0.8 billion for potential acquisitions and/or construction of new generating facilities.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; 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; 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; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy.

In addition, the construction program includes the development and construction of new generating facilities with designs that have not been finalized or previously constructed, including 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, 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 any PSC).

See "Regulation – Environmental Statutes and Regulations" herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information concerning Alabama Power's, Georgia Power's, and Southern Power's joint ownership of certain generating units and related facilities with certain non-affiliated utilities. See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4. Also see Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein for additional information regarding Mississippi Power's construction of the Kemper IGCC.

Financing Programs

See each of the registrant's MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY in Item 7 herein and Note 6 to the financial statements of each registrant in Item 8 herein for information concerning financing programs.

Fuel Supply

The traditional operating companies' and SEGCO's supply of electricity is primarily fueled by natural gas and coal. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Electricity Business – Fuel and Purchased Power Expenses" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Fuel and Purchased Power Expenses" of each traditional operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net KWH generated for the years 2013 through 2015.

The traditional operating companies have agreements in place from which they expect to receive substantially all of their coal burn requirements in 2016. These agreements have terms ranging between one and five years. In 2015, the weighted average sulfur content of all coal burned by the traditional operating companies was 0.95% sulfur. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional operating companies to remain within limits set by Phase I of the Cross-State Air Pollution Rule (CSAPR) under the Clean Air Act. In 2015, the Southern Company system did not purchase any sulfur dioxide allowances, annual nitrogen oxide emission allowances, or seasonal nitrogen oxide emission allowances from the market. As any additional environmental regulations are proposed that impact the utilization of coal, the traditional operating companies' fuel mix will be monitored to help ensure that the traditional operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for emissions control equipment, and potential unit retirements and replacements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each traditional operating company, and Southern Power in Item 7 herein for additional information on environmental matters.

SCS, acting on behalf of the traditional operating companies and Southern Power Company, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2016, SCS has contracted for 457 billion cubic feet of natural gas supply under agreements with remaining terms up to 15 years. In addition to natural gas supply, SCS has contracts in place for both firm natural gas transportation and storage. Management believes these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units.

Alabama Power and Georgia Power have numerous contracts covering a portion of their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. These contracts have varying expiration dates and most of them are for less than 10 years. Management believes sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of the Southern Company system's nuclear generating units.

Changes in fuel prices to the traditional operating companies are generally reflected in fuel adjustment clauses contained in rate schedules. See "Rate Matters – Rate Structure and Cost Recovery Plans" herein for additional information. Southern Power's PPAs (excluding solar and wind) generally provide that the counterparty is responsible for substantially all of the cost of fuel.

Alabama Power and Georgia Power have contracts with the United States, acting through the DOE, that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in 1998, as required by the contracts, and Alabama Power and Georgia Power have pursued and are pursuing legal remedies against the government for breach of contract. See Note 3 to the financial statements of Southern Company, Alabama Power, and Georgia Power under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information.

Territory Served by the Traditional Operating Companies and Southern Power

The territory in which the traditional operating companies provide electric service comprises most of the states of Alabama and Georgia, together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems that obtain some or all of their power requirements either directly or indirectly from the traditional operating companies. As of December 31, 2015, the territory had an area of approximately 120,000 square miles and an estimated population of approximately 17 million. Southern Power sells electricity at market-based rates in the wholesale market, primarily to investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load serving entities.

Alabama Power is engaged, within the State of Alabama, in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity, at retail in approximately 400 cities and towns (including Anniston, Birmingham, Gadsden, Mobile, Montgomery, and Tuscaloosa), as well as in rural areas, and at wholesale to 14 municipally-owned electric distribution systems, 11 of which are served indirectly through sales to AMEA, and two rural distributing cooperative associations. Alabama Power owns coal reserves near its Plant Gorgas and uses the output of coal from the reserves in its generating plants. Alabama Power also sells, and cooperates with dealers in promoting the sale of, electric appliances.

Georgia Power is engaged in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity within the State of Georgia, at retail in over 600 communities (including Athens, Atlanta, Augusta, Columbus, Macon, Rome, and Savannah), as well as in rural areas, and at wholesale currently to OPC, MEAG Power, Dalton, various EMCs, and non-affiliated utilities.

Gulf Power is engaged, within the northwestern portion of Florida, in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity, at retail in 71 communities (including Pensacola, Panama City, and Fort Walton Beach), as well as in rural areas, and at wholesale to a non-affiliated utility.

Mississippi Power is engaged in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity within 23 counties in southeastern Mississippi, at retail in 123 communities (including Biloxi, Gulfport, Hattiesburg, Laurel, Meridian, and Pascagoula), as well as in rural areas, and at wholesale to one municipality, six rural electric distribution cooperative associations, and one generating and transmitting cooperative.

For information relating to KWH sales by customer classification for the traditional operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS of each traditional operating company in Item 7 herein. Also, for information relating to the sources of revenues for Southern Company, each traditional operating company, and Southern Power, reference is made to Item 7 herein.

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. As of December 31, 2015, there were 71 electric cooperative organizations operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama and northwest Florida. As of December 31, 2015, PowerSouth owned generating units with approximately 2,100 MWs of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller. Alabama Power has a 15-year system supply agreement with PowerSouth to provide 200 MWs of capacity service with an option to extend and renegotiate in the event Alabama Power builds new generation or contracts for new capacity.

Alabama Power and Gulf Power have entered into separate agreements with PowerSouth involving interconnection between their respective systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the service territories of Alabama Power and Gulf Power is governed by the Southern Company/PowerSouth Network Transmission Service Agreement. The rates for this service to PowerSouth are on file with the FERC.

Four electric cooperative associations, financed by the RUS, operate within Gulf Power's service territory. These cooperatives purchase their full requirements from PowerSouth and SEPA (a federal power marketing agency). A non-affiliated utility also operates within Gulf Power's service territory and purchases its full requirements from Gulf Power.

Mississippi Power has an interchange agreement with SMEPA, a generating and transmitting cooperative, pursuant to which various services are provided.

As of December 31, 2015, there were approximately 65 municipally-owned electric distribution systems operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

As of December 31, 2015, 48 municipally-owned electric distribution systems and one county-owned system received their requirements through MEAG Power, which was established by a Georgia state statute in 1975. MEAG Power serves these requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and purchases from other resources. MEAG Power also has a pseudo scheduling and services agreement with Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and through purchases from Georgia Power and Southern Power through a service agreement. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Georgia Power has entered into substantially similar agreements with Georgia Transmission Corporation, MEAG Power, and Dalton providing for the establishment of an integrated transmission system to carry the power and energy of all parties. The agreements require an investment by each party in the integrated transmission system in proportion to its respective share of the aggregate system load. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Southern Power assumed or entered into PPAs with some of the traditional operating companies, investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load serving entities. See "The Southern Company System – Southern Power" above and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 herein for additional information concerning Southern Power's PPAs.

SCS, acting on behalf of the traditional operating companies, also has a contract with SEPA providing for the use of the traditional operating companies' facilities at government expense to deliver to certain cooperatives and municipalities, entitled by federal statute to preference in the purchase of power from SEPA, quantities of power equivalent to the amounts of power allocated to them by SEPA from certain U.S. government hydroelectric projects.

Competition

The electric utility industry in the U.S. is continuing to evolve as a result of regulatory and competitive factors. Among the early primary agents of change was the Energy Policy Act of 1992, which allowed IPPs to access a utility's transmission network in order to sell electricity to other utilities.

The competition for retail energy sales among competing suppliers of energy is influenced by various factors, including price, availability, technological advancements, service, and reliability. These factors are, in turn, affected by, among other influences, regulatory, political, and environmental considerations, taxation, and supply.

The retail service rights of all electric suppliers in the State of Georgia are regulated by the Territorial Electric Service Act of 1973. Pursuant to the provisions of this Act, all areas within existing municipal limits were assigned to the primary electric supplier therein. Areas outside of such municipal limits were either to be assigned or to be declared open for customer choice of supplier by action of the Georgia PSC pursuant to standards set forth in this Act. Consistent with such standards, the Georgia PSC has assigned substantially all of the land area in the state to a supplier. Notwithstanding such assignments, this Act provides that any new customer locating outside of 1973 municipal limits and having a connected load of at least 900 KWs may exercise a one-time choice for the life of the premises to receive electric service from the supplier of its choice.

Pursuant to the 1956 Utility Act, the Mississippi PSC issued "Grandfather Certificates" of public convenience and necessity to Mississippi Power and to six distribution rural cooperatives operating in southeastern Mississippi, then served in whole or in part by Mississippi Power, authorizing them to distribute electricity in certain specified geographically described areas of the state. The six cooperatives serve approximately 325,000 retail customers in a certificated area of approximately 10,300 square miles. In areas included in a "Grandfather Certificate," the utility holding such certificate may, without further certification, extend its lines up to five miles; other extensions within that area by such utility, or by other utilities, may not be made except upon a showing of, and a grant of a certificate of, public convenience and necessity. Areas included in such a certificate that are subsequently annexed to municipalities may continue to be served by the holder of the certificate, irrespective of whether it has a franchise in the annexing municipality. On the other hand, the holder of the municipal franchise may not extend service into such newly annexed area without authorization by the Mississippi PSC.

Generally, the traditional operating companies have experienced, and expect to continue to experience, competition in their respective retail service territories in varying degrees from the development and deployment of alternative energy sources such as self-generation (as described below) and distributed generation technologies, as well as other factors.

Southern Power competes with investor-owned utilities, IPPs, and others for wholesale energy sales primarily in the Southeastern U.S. wholesale market. The needs of this market are driven by the demands of end users in the Southeast and the generation available. Southern Power's success in wholesale energy sales is influenced by various factors including reliability and availability of Southern Power's plants, availability of transmission to serve the demand, price, and Southern Power's ability to contain costs.

As of December 31, 2015, Alabama Power had cogeneration contracts in effect with nine industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2015, Alabama Power purchased approximately 201 million KWHs from such companies at a cost of $4 million.

As of December 31, 2015, Georgia Power had contracts in effect with 24 small power producers whereby Georgia Power purchases their excess generation. During 2015, Georgia Power purchased 804 million KWHs from such companies at a cost of $60 million. Georgia Power also has PPAs for electricity with six cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2015, Georgia Power purchased 285 million KWHs at a cost of $25 million from these facilities.

Also during 2015, Georgia Power purchased energy from three customer-owned generating facilities. These customers provide only energy to Georgia Power and make no capacity commitment and are not dispatched by Georgia Power. During 2015, Georgia Power purchased a total of 34 million KWHs from the three customers at a cost of approximately $1 million.

As of December 31, 2015, Gulf Power had agreements in effect with various industrial, commercial, and qualifying facilities pursuant to which Gulf Power purchases "as available" energy from customer-owned generation. During 2015, Gulf Power purchased 211 million KWHs from such companies for approximately $6 million.

As of December 31, 2015, Mississippi Power had one cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2015, Mississippi Power did not purchase any excess generation from this customer.

Seasonality

The demand for electric power generation is affected by seasonal differences in the weather. At the traditional operating companies and Southern Power, the demand for power peaks either during the summer or winter months, with market prices reflecting the demand of power and available generating resources at that time. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional operating companies, and Southern Power have historically sold less power when weather conditions are milder.

Regulation

State Commissions

The traditional operating companies are subject to the jurisdiction of their respective state PSCs. The PSCs have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Traditional Operating Companies and Southern Power" and "Rate Matters" herein for additional information.

Federal Power Act

The traditional operating companies, Southern Power Company and certain of its generation subsidiaries, and SEGCO are all public utilities engaged in wholesale sales of energy in interstate commerce and, therefore, are subject to the rate, financial, and accounting jurisdiction of the FERC under the Federal Power Act. The FERC must approve certain financings and allows an "at cost standard" for services rendered by system service companies such as SCS and Southern Nuclear. The FERC is also authorized to establish regional reliability organizations which enforce reliability standards, address impediments to the construction of transmission, and prohibit manipulative energy trading practices.

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. As of December 31, 2015, among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,667,000 KWs and 18 existing Georgia Power generating stations having an aggregate installed capacity of 1,087,296 KWs.

In 2013, the FERC issued a new 30-year license to Alabama Power for Alabama Power's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin). Alabama Power filed a petition requesting rehearing of the FERC order granting the relicense seeking revisions to several conditions of the license. The Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission have also filed petitions for rehearing of the FERC order.

In 2013, Alabama Power filed an application with the FERC to relicense the Holt hydroelectric project located on the Warrior River. The current Holt license expired on August 31, 2015. Since the FERC did not act on Alabama Power's new license application prior to the expiration of the existing license, the FERC issued to Alabama Power an annual license authorizing continued operation of the project under the terms and conditions of the expired license until action is taken on the new license.

On December 17, 2015, the FERC issued a new 30-year license to Alabama Power for the Martin Dam project located on the Tallapoosa River. The Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission have filed petitions for rehearing of the FERC order.

In 2015, Georgia Power initiated the process of developing an application to relicense the Wallace Dam project on the Oconee River. The current Wallace Dam project license will expire on June 1, 2020.

Georgia Power and OPC also have a license, expiring in 2027, for the Rocky Mountain Plant, a pure pumped storage facility of 847,800 KW capacity. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Licenses for all projects, excluding those discussed above, expire in the years 2023-2035 in the case of Alabama Power's projects and in the years 2020-2044 in the case of Georgia Power's projects.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property. The FERC may grant relicenses subject to certain requirements that could result in additional costs.

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

Nuclear Regulation

Alabama Power, Georgia Power, and Southern Nuclear are subject to regulation by the NRC. The NRC is responsible for licensing and regulating nuclear facilities and materials and for conducting research in support of the licensing and regulatory process, as mandated by the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and the Nuclear Nonproliferation Act of 1978; and in accordance with the National Environmental Policy Act of 1969, as amended, and other applicable statutes. These responsibilities also include protecting public health and safety, protecting the environment, protecting and safeguarding nuclear materials and nuclear power plants in the interest of national security, and assuring conformity with antitrust laws.

The NRC licenses for Georgia Power's Plant Hatch Units 1 and 2 expire in 2034 and 2038, respectively. The NRC licenses for Alabama Power's Plant Farley Units 1 and 2 expire in 2037 and 2041, respectively. The NRC licenses for Plant Vogtle Units 1 and 2 expire in 2047 and 2049, respectively.

In 2012, the NRC issued combined construction and operating licenses (COLs) for Plant Vogtle Units 3 and 4. Receipt of the COLs allowed full construction to begin. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 herein for additional information.

See Notes 1 and 9 to the financial statements of Southern Company, Alabama Power, and Georgia Power in Item 8 herein for information on nuclear decommissioning costs and nuclear insurance.

Environmental Statutes and Regulations

The electric utilities' operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions or through market-based contracts. There is no assurance, however, that all such costs will be recovered.

Compliance with federal environmental statutes and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional operating company, Southern Power, and SEGCO. In addition, existing environmental laws and regulations may be changed or new laws and regulations may be adopted or otherwise become applicable to the Southern Company system, including laws and regulations designed to address air quality, water, CCRs, global climate change, or other environmental and health concerns, as well as wildlife and endangered species conservation. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each of the traditional operating companies in Item 7 herein for additional information about environmental issues, including, but not limited to, proposed and final regulations related to air quality, water, CCRs, and greenhouse gases. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 herein for additional information about environmental issues and climate change regulation.

The Southern Company system'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; 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 and 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 and costs; and the fuel mix of the electric utilities. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered on a timely basis through regulated rates or long-term wholesale agreements for the traditional operating companies or market-based rates for Southern Power. 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. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each of the traditional operating companies, and Southern Power in Item 7 herein for additional information. The ultimate outcome of these matters cannot be determined at this time.

Compliance with any new federal or state legislation or regulations relating to air, water, and land resources or other environmental and health concerns could significantly affect the Southern Company system. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity. See "Construction Program" herein for additional information.

Rate Matters

Rate Structure and Cost Recovery Plans

The rates and service regulations of the traditional operating companies are uniform for each class of service throughout their respective retail service territories. Rates for residential electric service are generally of the block type based upon KWHs used and include minimum charges. Residential and other rates contain separate customer charges. Rates for commercial service are presently of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer and include rates with special features to encourage off-peak usage. Additionally, Alabama Power, Gulf Power, and Mississippi Power are generally allowed by their respective state PSCs to negotiate the terms and cost of service to large customers. Such terms and cost of service, however, are subject to final state PSC approval.

The traditional operating companies recover their respective costs through a variety of forward-looking, cost-based rate mechanisms. Fuel and net purchased energy costs are recovered through specific fuel cost recovery provisions. These fuel cost recovery provisions are adjusted to reflect increases or decreases in such costs as needed or on schedules as required by the respective PSCs. Approved environmental compliance, storm damage, and certain other costs are recovered at Alabama Power, Gulf Power, and Mississippi Power through specific cost recovery mechanisms approved by their respective PSCs. Certain similar costs at Georgia Power are recovered through various base rate tariffs as approved by the Georgia PSC. Costs not recovered through specific cost recovery mechanisms are recovered at Alabama Power and Mississippi Power through annual, formulaic cost recovery proceedings and at Georgia Power and Gulf Power through base rate proceedings.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters" of Southern Company and each of the traditional operating companies in Item 7 herein and Note 3 to the financial statements of Southern Company and each of the traditional operating companies under "Retail Regulatory Matters" in Item 8 herein for a discussion of rate matters and certain cost recovery mechanisms. Also, see Note 1 to the financial statements of Southern Company and each of the traditional operating companies in Item 8 herein for a discussion of recovery of fuel costs, storm damage costs, and environmental compliance costs through rate mechanisms.

See "Integrated Resource Planning" herein for a discussion of Georgia PSC certification of new demand-side or supply-side resources and decertification of existing supply-side resources for Georgia Power. In addition, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 herein for a discussion of the Georgia Nuclear Energy Financing Act and the Georgia PSC certification of Plant Vogtle Units 3 and 4, which have allowed Georgia Power to recover financing costs for construction of Plant Vogtle Units 3 and 4 during the construction period beginning in 2011.

See Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" of Mississippi Power in Item 7 herein for information on cost recovery plans with respect to the Kemper IGCC.

The traditional operating companies and Southern Power Company and certain of its generation subsidiaries are authorized by the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of each of the registrants in Item 7 herein for information on the traditional operating companies' and Southern Power Company's market-based rate authority and a pending FERC proceeding relating to this authority.

Through 2015, capacity revenues represented the majority of Gulf Power's wholesale earnings. Gulf Power had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 (205 MWs) and these capacity revenues represented 82% of total wholesale capacity revenues for 2015. Due to the expiration of a wholesale contract at the end of 2015 and future expiration dates of the remaining wholesale contracts for the unit, Gulf Power currently has contracts to cover 34% of the unit for 2016 and 27% of the unit through 2019. Although Gulf Power is actively evaluating alternatives relating to this asset, including replacement wholesale contracts, the expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts will have a material negative impact on Gulf Power's earnings in 2016 and may continue to have a material negative impact in future years. In the event some portion of Gulf Power's ownership of Plant Scherer Unit 3 is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the power pool or into the wholesale market.

Mississippi Power serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 21.0% of Mississippi Power's operating revenues in 2015 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.

Integrated Resource Planning

Each of the traditional operating companies continually evaluates its electric generating resources in order to ensure that it maintains a cost-effective and reliable mix of resources to meet the existing and future demand requirements of its customers. See "Environmental Statutes and Regulations" above for a discussion of existing and potential environmental regulations that may impact the future generating resource needs of the traditional operating companies.

Certain of the traditional operating companies periodically file IRPs with their respective state PSC as discussed below.

Georgia Power

Triennially, Georgia Power must file an IRP with the Georgia PSC that specifies how it intends to meet the future electrical needs of its customers through a combination of demand-side and supply-side resources. The Georgia PSC, under state law, must certify any new demand-side or supply-side resources for Georgia Power to receive cost recovery. Once certified, the lesser of actual or certified construction costs and purchased power costs is recoverable through rates. Certified costs may be excluded from recovery only on the basis of fraud, concealment, failure to disclose a material fact, imprudence, or criminal misconduct.

See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Rate Plans," "– Integrated Resource Plan," and "– Nuclear Construction" and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Rate Plans," "– Integrated Resource Plan," and "– Nuclear Construction" in Item 8 herein for additional information.

Gulf Power

Annually by April 1, Gulf Power must file a 10-year site plan with the Florida PSC containing Gulf Power's estimate of its power-generating needs in the period and the general location of its proposed power plant sites. The 10-year site plans submitted by the state's electric utilities are reviewed by the Florida PSC and subsequently classified as either "suitable" or "unsuitable." The Florida PSC then reports its findings along with any suggested revisions to the Florida Department of Environmental Protection for its consideration at any subsequent electrical power plant site certification proceedings. Under Florida law, any 10-year site plans submitted by an electric utility are considered tentative information for planning purposes only and may be amended at any time at the discretion of the utility with written notification to the Florida PSC.

Gulf Power's most recent 10-year site plan was classified by the Florida PSC as "suitable" in November 2015. Gulf Power's most recent 10-year site plan and environmental compliance plan identify environmental regulations and potential legislation or regulation that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Environmental Statutes and Regulations – Coal Combustion Residuals," and "– Global Climate Issues" of Gulf Power in Item 7 herein. Gulf Power continues to evaluate the economics of various potential planning scenarios for units at certain Gulf Power coal-fired generating plants as EPA and other regulations develop.

On February 6, 2015, Gulf Power announced plans to retire its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016, as a result of the cost to comply with environmental regulations imposed by the EPA. In connection with this retirement, Gulf Power reclassified the net carrying value of these units from plant in service, net of depreciation, to other utility plant, net. The net book value of these units at December 31, 2015 was approximately $62 million. Subsequent to December 31, 2015, Gulf Power filed a petition with the Florida PSC requesting permission to create a regulatory asset for the remaining net book value of Plant Smith Units 1 and 2 and the remaining inventory associated with these units as of the retirement date. The retirement of these units is not expected to have a material impact on Gulf Power's financial statements as Gulf Power expects to recover these amounts through its rates; however, the ultimate outcome depends on future rate proceedings with the Florida PSC and cannot be determined at this time.

Mississippi Power

Mississippi Power's 2010 IRP indicated that Mississippi Power plans to construct the Kemper IGCC to meet its identified needs, to add environmental controls at Plant Daniel Units 1 and 2, to defer environmental controls at Plant Watson Units 4 and 5, and to continue operation of the combined cycle Plant Daniel Units 3 and 4. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" and "– Global Climate Issues" of Mississippi Power in Item 7 herein. In August 2014, Mississippi Power 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 Kemper IGCC and the flue gas desulfurization system project at Plant Daniel Units 1 and 2, which also occurred in August 2014. In addition, and consistent with Mississippi Power’s ongoing evaluation of recent environmental rules and regulations, Mississippi Power 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. Mississippi Power also agreed that it would cease burning coal or 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 on April 16, 2015), and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016.

For information regarding Mississippi Power's construction of the Kemper IGCC, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein.

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

Employee Relations

The Southern Company system had a total of 26,703 employees on its payroll at December 31, 2015.

	Employees at December 31, 2015
Alabama Power	6,986
Georgia Power	7,989
Gulf Power	1,391
Mississippi Power	1,478
SCS	4,609
Southern Nuclear	4,012
Southern Power*	0
Other	238
Total	26,703

* Southern Power has no employees. Southern Power has agreements with SCS and the traditional operating companies whereby employee services are rendered at amounts in compliance with FERC regulations.

The traditional operating companies have separate agreements with local unions of the IBEW generally covering wages, working conditions, and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance, and construction employees.

Alabama Power has agreements with the IBEW in effect through August 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Georgia Power has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2016.

Gulf Power has an agreement with the IBEW covering wages and working conditions, which is in effect through April 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect through May 1, 2019. In 2013, Mississippi Power signed a separate agreement with the IBEW related solely to the Kemper IGCC, which is in effect through March 15, 2021.

Southern Nuclear has an agreement with the IBEW covering certain employees at Plants Hatch and Vogtle which is in effect through June 30, 2016. A five-year agreement between Southern Nuclear and the IBEW representing certain employees at Plant Farley is in effect through August 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

The agreements also make the terms of the pension plans for the companies discussed above subject to collective bargaining with the unions at either a five-year or a 10-year cycle, depending upon union and company actions.

Item 1A. RISK FACTORS

In addition to the other information in this Form 10-K, including MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL in Item 7 of each registrant, and other documents filed by Southern Company and/or its subsidiaries with the SEC from time to time, the following factors should be carefully considered in evaluating Southern Company and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by, or on behalf of, Southern Company and/or its subsidiaries.

UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS

Southern Company and its subsidiaries are subject to substantial governmental regulation. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits, and certificates may result in substantial costs to Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, are subject to substantial regulation from federal, state, and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of their businesses, including rates and charges, service regulations, retail service territories, sales of securities, incurrence of indebtedness, asset acquisitions and sales, accounting and tax policies and practices, physical security and cyber-security policies and practices, and the construction and operation of fossil-fuel, nuclear, hydroelectric, solar, wind, and biomass generating facilities, as well as transmission and distribution facilities. For example, the respective state PSCs must approve the traditional operating companies' requested rates for retail customers. The traditional operating companies seek to recover their costs (including a reasonable return on invested capital) through their retail rates, and there can be no assurance that a state PSC, in a future rate proceeding, will not alter the timing or amount of certain costs for which recovery is allowed or modify the current authorized rate of return. Additionally, the rates charged to wholesale customers by the traditional operating companies and by Southern Power must be approved by the FERC. These wholesale rates could be affected by changes to Southern Power's ability to conduct business pursuant to FERC market-based rate authority. The FERC rules related to retaining the authority to sell electricity at market-based rates in the wholesale markets are important for the traditional operating companies and Southern Power if they are to remain competitive in the wholesale markets in which they operate.

The impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries cannot now be predicted. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs or otherwise negatively affect their results of operations.

The Southern Company system's costs of compliance with environmental laws are significant. The costs of compliance with current and future environmental laws, including laws and regulations designed to address air quality, water, CCR, global climate change, and other matters and the incurrence of environmental liabilities could negatively impact the net income, cash flows, and financial condition of Southern Company, the traditional operating companies, and/or Southern Power.

The Southern Company system is subject to extensive federal, state, and local environmental requirements which, among other things, regulate air emissions, water usage and discharges, and the management and disposal of waste in order to adequately protect the environment. Compliance with these environmental requirements requires the traditional operating companies and Southern Power to commit significant expenditures for installation of pollution control equipment, environmental monitoring, emissions fees, and permits at substantially all of their respective facilities. Southern Company, the traditional operating companies, and Southern Power expect that these expenditures will continue to be significant in the future.

On October 23, 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 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. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for its review with the courts. The stay will remain in effect through the resolution of the litigation, whether resolved in the D.C. Circuit or the Supreme Court.

Costs associated with these actions could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the final rules on the Southern Company system cannot be determined at this time and will depend upon numerous factors, including the Southern Company system's ongoing review of the final rules; the outcome of legal challenges, including legal challenges filed by the traditional operating companies; individual state implementation of the EPA's final guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

The EPA has adopted and is in the process of implementing regulations governing air quality, including the emission of nitrogen oxide, sulfur dioxide, fine particulate matter, ozone, mercury, and other air pollutants under the Clean Air Act. In addition, the EPA has finalized regulations governing cooling water intake structures, effluent guidelines for steam electric generating plants, and amending the definition of Waters of the United States under the Clean Water Act. The EPA has also finalized regulations governing the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments at active power generation plants.

Existing environmental laws and regulations may be revised or new laws and regulations related to air quality, water, CCR, global climate change, endangered species, or other environmental and health concerns may be adopted or become applicable to the traditional operating companies and/or Southern Power.

The Southern Company system'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; 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 and 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 and costs; and the fuel mix of the electric utilities. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered on a timely basis through regulated rates or long-term wholesale agreements for the traditional operating companies or market-based rates for Southern Power. 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. Additionally, if Southern Company, any traditional operating company, or Southern Power fails to comply with environmental laws and regulations, even if caused by factors beyond its control, that failure may result in the assessment of civil or criminal penalties and fines and/or remediation costs.

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 cost impact of proposed and final legislation and regulations and litigation are likely to result in significant additional costs and could result in additional operating restrictions.

The net income of Southern Company, the traditional operating companies, and Southern Power could be negatively impacted by changes in regulations related to transmission planning processes and competition in the wholesale electric markets.

The traditional operating companies currently own and operate transmission facilities as part of a vertically integrated utility. A small percentage of transmission revenues are collected through the wholesale electric tariff but the majority of transmission revenues are collected through retail rates. FERC rules pertaining to regional transmission planning and cost allocation present challenges to transmission planning and the wholesale market structure in the Southeast. The key impacts of these rules include:

- possible disruption of the integrated resource planning processes within the states in the Southern Company system's service territory;
- delays and additional processes for developing transmission plans; and
- possible impacts on state jurisdiction of approving, certifying, and pricing new transmission facilities.

The FERC rules related to transmission are intended to spur the development of new transmission infrastructure to promote and encourage the integration of renewable sources of supply as well as facilitate competition in the wholesale market by providing more choices to wholesale power customers. In addition to the impacts on transactions contemplating physical delivery of energy, financial laws and regulations also impact power hedging and trading based on futures contracts and derivatives that are traded on various commodities exchanges as well as over-the-counter. Finally, technology changes in the power and fuel industries continue to create significant impacts to wholesale transaction cost structures. Southern Company, the traditional operating companies, and Southern Power cannot predict the impact of these and other such developments, nor can they predict the effect of changes in levels of wholesale supply and demand, which are typically driven by factors beyond their control. The financial condition, net income, and cash flows of Southern Company, the traditional operating companies, and Southern Power could be adversely affected by these and other changes.

The traditional operating companies and Southern Power could be subject to higher costs as a result of implementing and maintaining compliance with the North American Electric Reliability Corporation mandatory reliability standards along with possible associated penalties for non-compliance.

Owners and operators of bulk power systems, including the traditional operating companies, are subject to mandatory reliability standards enacted by the North American Electric Reliability Corporation and enforced by the FERC. Compliance with or changes in the mandatory reliability standards may subject the traditional operating companies, Southern Power, and Southern Company to higher operating costs and/or increased capital expenditures. If any traditional operating company or Southern Power is found to be in noncompliance with the mandatory reliability standards, such traditional operating company or Southern Power could be subject to sanctions, including substantial monetary penalties.

OPERATIONAL RISKS

The financial performance of Southern Company and its subsidiaries may be adversely affected if the subsidiaries are unable to successfully operate their facilities or perform certain corporate functions.

The financial performance of Southern Company and its subsidiaries depends on the successful operation of its subsidiaries' electric generating, transmission, and distribution facilities and the successful performance of necessary corporate functions. There are many risks that could affect these operations and performance of corporate functions, including:

- operator error or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- terrorist attacks (physical and/or cyber);
- fuel or material supply interruptions;
- transmission disruption or capacity constraints, including with respect to the Southern Company system’s transmission facilities and third party transmission facilities;
- compliance with mandatory reliability standards, including mandatory cyber security standards;
- implementation of new technologies;
- information technology system failure;
- cyber intrusion;
- an environmental event, such as a spill or release; and
- catastrophic events such as fires, earthquakes, explosions, floods, droughts, hurricanes, pandemic health events such as influenzas, or other similar occurrences.

A decrease or elimination of revenues from the electric generation, transmission, or distribution facilities or an increase in the cost of operating the facilities would reduce the net income and cash flows and could adversely impact the financial condition of the affected traditional operating company or Southern Power and of Southern Company.

Operation of nuclear facilities involves inherent risks, including environmental, safety, health, regulatory, natural disasters, terrorism, and financial risks, that could result in fines or the closure of the nuclear units owned by Alabama Power or Georgia Power and which may present potential exposures in excess of insurance coverage.

Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units. The six existing units are operated by Southern Nuclear and represent approximately 3,680 MWs, or 8%, of the Southern Company system's generation capacity as of December 31, 2015. In addition, these units generated approximately 23% and 25% of the total KWHs generated by Alabama Power and Georgia Power, respectively, in the year ended December 31, 2015. In addition, Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of Plant Vogtle Units 3 and 4. Due solely to the increase in nuclear generating capacity, the below risks are expected to increase incrementally once Plant Vogtle Units 3 and 4 are operational. Nuclear facilities are subject to environmental, safety, health, operational, and financial risks such as:

- the potential harmful effects on the environment and human health and safety resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling, and disposal of radioactive material, including spent nuclear fuel;
- uncertainties with respect to the ability to dispose of spent nuclear fuel and the need for longer term on-site storage;
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of licensed lives and the ability to maintain and anticipate adequate capital reserves for decommissioning;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with the nuclear operations of Alabama Power and Georgia Power or those of other commercial nuclear facility owners in the U.S.;
- potential liabilities arising out of the operation of these facilities;
- significant capital expenditures relating to maintenance, operation, security, and repair of these facilities, including repairs and upgrades required by the NRC;
- the threat of a possible terrorist attack, including a potential cyber security attack; and
- the potential impact of an accident or natural disaster.

It is possible that damages, decommissioning, or other costs could exceed the amount of decommissioning trusts or external insurance coverage, including statutorily required nuclear incident insurance.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance with NRC licensing and safety-related requirements, the NRC has the authority to impose fines and/or shut down any unit, depending upon its assessment of the severity of the situation, until compliance is achieved. NRC orders or regulations related to increased security measures and any future safety requirements promulgated by the NRC could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants. In addition, if a serious nuclear incident were to occur, it could result in substantial costs to Alabama Power or Georgia Power and Southern Company. A major incident at a nuclear facility anywhere in the world could cause the NRC to delay or prohibit construction of new nuclear units or require additional safety measures at new and existing units. Moreover, a major incident at any nuclear facility in the U.S., including facilities owned and operated by third parties, could require Alabama Power and Georgia Power to make material contributory payments.

In addition, potential terrorist threats and increased public scrutiny of utilities could result in increased nuclear licensing or compliance costs that are difficult to predict.

Physical or cyber attacks, both threatened and actual, could impact the ability of the traditional operating companies and Southern Power to operate and could adversely affect financial results and liquidity.

The traditional operating companies and Southern Power face the risk of physical and cyber attacks, both threatened and actual, against their respective generation facilities, the transmission and distribution infrastructure used to transport power, and their information technology systems and network infrastructure, which could negatively impact the ability of the traditional operating companies or Southern Power to generate, transport, and deliver power, or otherwise operate their respective facilities in the most efficient manner or at all. In addition, physical or cyber attacks against key suppliers or service providers could have a similar effect on Southern Company and its subsidiaries.

The traditional operating companies and Southern Power operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure, which are part of an interconnected regional grid. In addition, in the ordinary course of business, the traditional operating companies and Southern Power collect and retain sensitive information including personal identification information about customers and employees and other confidential information. The traditional operating companies and Southern Power face on-going threats to their assets. Despite the implementation of robust security measures, all assets are potentially vulnerable to disability, failures, or unauthorized access due to human error, natural disasters, technological failure, or internal or external physical or cyber attacks. If the traditional operating companies' or Southern Power's assets were to fail, be physically damaged, or be breached and were not recovered in a timely way, the traditional operating companies or Southern Power may be unable to fulfill critical business functions, and sensitive and other data could be compromised. Any physical security breach, cyber breach or theft, damage, or improper disclosure of sensitive electronic data may also subject the applicable traditional operating company or Southern Power to penalties and claims from regulators or other third parties.

These events could harm the reputation of and negatively affect the financial results of Southern Company, the traditional operating companies, or Southern Power through lost revenues, costs to recover and repair damage, and costs associated with governmental actions in response to such attacks.

The traditional operating companies and Southern Power may not be able to obtain adequate fuel supplies, which could limit their ability to operate their facilities.

The traditional operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, fuel oil, and biomass, from a number of suppliers. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting any of these fuel suppliers, could limit the ability of the traditional operating companies and Southern Power to operate certain facilities, which could result in higher fuel and operating costs and potentially reduce the net income of the affected traditional operating company or Southern Power and Southern Company.

The traditional operating companies and Southern Power have become more dependent on natural gas for a portion of their electric generating capacity. In many instances, the cost of purchased power for the traditional operating companies and Southern Power is influenced by natural gas prices. Historically, natural gas prices have been more volatile than prices of other fuels. In recent years, domestic natural gas prices have been depressed by robust supplies, including production from shale gas. These market conditions, together with additional regulation of coal-fired generating units, have increased the traditional operating companies' reliance on natural gas-fired generating units.

Natural gas supplies can be subject to disruption in the event production or distribution is curtailed, such as in the event of a hurricane, freezing wells, or a pipeline failure. The availability of shale gas and potential regulations affecting its accessibility may have a material impact on the supply and cost of natural gas.

The traditional operating companies are also dependent on coal for a portion of their electric generating capacity. The traditional operating companies depend on coal supply contracts, and there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal to the traditional operating companies. The suppliers under these agreements may experience financial or technical problems that inhibit their ability to fulfill their obligations to the traditional operating companies. In addition, the suppliers under these agreements may not be required to supply coal to the traditional operating companies under certain circumstances, such as in the event of a natural disaster. If the traditional operating companies are unable to obtain their coal requirements under these contracts, the traditional operating companies may be required to purchase their coal requirements at higher prices, which may not be recoverable through rates.

The revenues of Southern Company, the traditional operating companies, and Southern Power depend in part on sales under PPAs. The failure of a counterparty to one of these PPAs to perform its obligations, the failure of the traditional operating companies or Southern Power to satisfy minimum requirements under the PPAs, or the failure to renew the PPAs or successfully remarket the related generating capacity, could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company.

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. Southern Power’s top three customers, Georgia Power, Florida Power & Light Company, and Duke Energy Corporation, accounted for 15.8%, 10.7%, and 8.2%, respectively, of Southern Power’s total revenues for the year ended December 31, 2015. In addition, the traditional operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. The failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company. Although the credit evaluations undertaken and contractual protections implemented by Southern Power and the traditional operating companies take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than predicted or specified in the applicable contract. Additionally, neither Southern Power nor any traditional operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. As an example, Gulf Power had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 (205 MWs) and these capacity revenues represented 82% of Gulf Power's total wholesale capacity revenues for 2015. Due to the expiration of a wholesale contract at the end of 2015 and future expiration dates of the remaining wholesale contracts for the unit, Gulf Power currently has contracts to cover 34% of the unit for 2016 and 27% of the unit through 2019. Although Gulf Power is actively evaluating alternatives relating to this asset, including replacement wholesale contracts, the expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts will have a material negative impact on Gulf Power's earnings in 2016 and may continue to have a material negative impact in future years. In addition, the failure of the traditional operating companies or Southern Power to satisfy minimum operational or availability requirements under these PPAs could result in payment of damages or termination of the PPAs.

Changes in technology may make Southern Company's electric generating facilities owned by the traditional operating companies and Southern Power less competitive.

A key element of the business models of Southern Company, the traditional operating companies, and Southern Power is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. There are distributed generation and storage technologies that produce and store power, including fuel cells, microturbines, wind turbines, solar cells, and batteries. Advances in technology or changes in laws or regulations could reduce the cost of these or other alternative methods of producing power to a level that is competitive with that of most central station power electric production or result in smaller-scale, more fuel efficient, and/or more cost effective distributed generation. Broader use of distributed generation by retail electric customers may also result from customers' changing perceptions of the merits of utilizing existing generation technology or tax or other economic incentives. Additionally, there can be no assurance that a state PSC or legislature will not attempt to modify certain aspects of the traditional operating companies' business as a result of these advances in technology. If these technologies became cost competitive and achieve sufficient scale, the market share of the traditional operating companies and Southern Power could be eroded, and the value of their respective electric generating facilities could be reduced. It is also possible that rapid advances in central station power generation technology could reduce the value of the current electric generating facilities owned by the traditional operating companies and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional operating companies, or Southern Power. If state PSCs fail to adjust rates to reflect the impact of any changes in loads, increasing self-generation, and the growth of distributed generation, the financial condition, results of operations, and cash flows of Southern Company and the traditional operating companies could be materially adversely affected.

Failure to attract and retain an appropriately qualified workforce could negatively impact Southern Company's and its subsidiaries' results of operations.

Events such as an aging workforce without appropriate replacements, mismatch of skill sets to future needs, or unavailability of contract resources may lead to operating challenges such as lack of resources, loss of knowledge, and a lengthy time period associated with skill development, including with the workforce needs associated with major construction projects and ongoing operations. The Southern Company system's costs, including costs for contractors to replace employees, productivity costs, and safety costs, may rise. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Southern Company and its subsidiaries' ability to manage and operate their businesses. If Southern Company and its subsidiaries, including the traditional operating companies, are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

CONSTRUCTION RISKS

Southern Company, the traditional operating companies, and/or Southern Power may incur additional costs or delays in the construction of new plants or other facilities and may not be able to recover their investments. Also, existing facilities of the traditional operating companies and Southern Power require ongoing capital expenditures, including those to meet environmental standards.

General

The businesses of the registrants require substantial capital expenditures for investments in new facilities and capital improvements to transmission, distribution, and generation facilities, including those to meet environmental standards. Certain of the traditional operating companies and Southern Power are in the process of constructing new generating facilities and adding environmental controls equipment at existing generating facilities. The Southern Company system intends to continue its strategy of developing and constructing other new facilities, expanding existing facilities, and adding environmental control equipment. These types of projects are long-term in nature and in some cases include the development and construction of facilities with designs that have not been finalized or previously constructed. The completion of these types of projects without delays or significant cost overruns is subject to substantial risks, including:

- shortages and inconsistent quality of equipment, materials, and labor;
- changes in labor costs and productivity;
- work stoppages;
- contractor or supplier delay or non-performance under construction or other agreements or non-performance by other major participants in construction projects;
- delays in or failure to receive necessary permits, approvals, tax credits, and other regulatory authorizations;

- delays associated with 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 any PSC);
- operational readiness, including specialized operator training and required site safety programs;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- the outcome of legal challenges to projects, including legal challenges to regulatory approvals;
- failure to construct in accordance with licensing requirements;
- continued public and policymaker support for such projects;
- adverse weather conditions or natural disasters;
- other unforeseen engineering or design problems;
- changes in project design or scope;
- environmental and geological conditions;
- delays or increased costs to interconnect facilities to transmission grids; and
- unanticipated cost increases, including materials and labor, and increased financing costs as a result of changes in market interest rates or as a result of construction schedule delays.

If a traditional operating company or Southern Power is unable to complete the development or construction of a facility or decides to delay or cancel construction of a facility, it may not be able to recover its investment in that facility and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Even if a construction project is completed, the total costs may be higher than estimated and there is no assurance that the traditional operating company will be able to recover such expenditures through regulated rates. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of a traditional operating company or Southern Power and of Southern Company.

Construction delays could result in the loss of otherwise available investment tax credits, production tax credits, and other tax incentives. Furthermore, if construction projects are not completed according to specification, a traditional operating company or Southern Power and Southern Company may incur liabilities and suffer reduced plant efficiency, higher operating costs, and reduced net income.

Once facilities come into commercial operation, ongoing capital expenditures are required to maintain reliable levels of operation. Significant portions of the traditional operating companies' existing facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements, or to provide reliable operations.

The two largest construction projects currently underway in the Southern Company system are the construction of Plant Vogtle Units 3 and 4 and the Kemper IGCC. In addition, Southern Power has 691 MWs (based on its equity ownership) of renewable generation under construction at eight project sites.

Plant Vogtle Units 3 and 4 construction

Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of and will operate Plant Vogtle Units 3 and 4 (each, an approximately 1,100 MW AP1000 nuclear generating unit). Georgia Power owns 45.7% of the new units. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined COLs in early 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges may arise as construction proceeds.

Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected construction capital costs to be borne by Georgia Power increase by 5% above the certified cost or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. In February 2013, Georgia Power requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 (from April 2016) and the fourth quarter 2018 (from April 2017) for Plant Vogtle Units 3 and 4, respectively. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between Georgia Power and the Georgia PSC Staff (Staff) to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and Georgia Power.

On April 15, 2015, the Georgia PSC issued a procedural order in connection with the twelfth VCM report, which included a requested amendment (Requested Amendment) to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 (second quarter of 2019 and second quarter of 2020, respectively) as well as additional estimated Vogtle Owner's costs, of approximately $10 million per month, including property taxes, oversight costs, compliance costs, and other operational readiness costs to include the estimated Vogtle Owner's costs associated with the proposed 18-month Contractor delay and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion. Pursuant to the Georgia PSC's procedural order, the Georgia PSC deemed the Requested Amendment unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation. The Georgia PSC recognized that the certified cost and the 2013 Stipulation do not constitute a cost recovery cap.

In 2012, the Vogtle Owners and the Contractor commenced litigation (Vogtle Construction Litigation) regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Vogtle Owners are responsible for these costs under the terms of the engineering, procurement, and construction contract between the Vogtle Owners and the Contractor (Vogtle 3 and 4 Agreement).

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including the Vogtle Construction Litigation. Effective December 31, 2015, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to match the current estimated in-service dates of June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will now commence from the current estimated nuclear fuel loading date for each unit, which is December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4, rather than the original guaranteed substantial completion dates under the Vogtle 3 and 4 Agreement; and (v) provide that Georgia Power, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million, of which approximately $120 million has been paid previously under the dispute resolution procedures of the Vogtle 3 and 4 Agreement. Further, subsequent to December 31, 2015, Georgia Power paid approximately $121 million under the terms of the Contractor Settlement Agreement. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs were reflected in Georgia Power's previously disclosed in-service cost estimate. Further, as part of the settlement: (i) Westinghouse has engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor; and (ii) the Vogtle Owners, Chicago Bridge & Iron Company N.V., and The Shaw Group Inc. have entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On January 21, 2016, Georgia Power submitted the Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement to the Georgia PSC for its review. On February 2, 2016, the Georgia PSC ordered Georgia Power to file supplemental information by April 5, 2016 in support of the Contractor Settlement Agreement and Georgia Power's position that all construction costs to date have been prudently incurred and that the current estimated in-service capital cost and schedule are reasonable. Following Georgia Power's filing under the order, the Staff will conduct a review of all costs incurred related to Plant Vogtle Units 3 and 4, the schedule for completion of Plant Vogtle Units 3 and 4, and the Contractor Settlement Agreement and the Staff is authorized to engage in related settlement discussions with Georgia Power and any intervenors.

The order provides that the Staff is required to report to the Georgia PSC by October 5, 2016 with respect to the status of its review and any settlement-related negotiations. If a settlement with the Staff is reached with respect to costs of Plant Vogtle Units 3 and 4, the Georgia PSC will then conduct a hearing to consider whether to approve that settlement. If a settlement with the Staff is not reached, the Georgia PSC will determine how to proceed, including (i) modifying the 2013 Stipulation, (ii) directing Georgia Power to file a request for an amendment to the certificate for Plant Vogtle Units 3 and 4, (iii) issuing a scheduling order to address remaining disputed issues, or (iv) taking any other option within its authority.

The Georgia PSC has approved thirteen VCM reports covering the periods through June 30, 2015, including construction capital costs incurred, which through that date totaled $3.1 billion. On February 26, 2016, Georgia Power filed its fourteenth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2015. The fourteenth VCM report does not include a requested amendment to the certified cost of Plant Vogtle Units 3 and 4. Georgia Power is requesting approval of $160 million of construction capital costs incurred during that period. Georgia Power anticipates to incur average financing costs of approximately $27 million per month from January 2016 until Plant Vogtle Units 3 and 4 are placed in service. The updated in-service capital cost forecast is $5.44 billion and includes costs related to the Contractor Settlement Agreement. Estimated financing costs during the construction period total approximately $2.4 billion. Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.6 billion as of December 31, 2015.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance issues may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

As construction continues, the risk remains that challenges with Contractor performance including fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the Internal Revenue Service allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Future claims by the Contractor or Georgia Power (on behalf of the Vogtle Owners) could arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement and, under the enhanced dispute resolution procedures, may be resolved through litigation after the completion of nuclear fuel load for both units.

Kemper IGCC construction

In 2012, the Mississippi PSC issued a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC (2012 MPSC CPCN Order). The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion, net of $245 million of DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper IGCC was originally projected to be placed in service in May 2014. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service using natural gas in August 2014 and currently expects to place the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, in service during the third quarter 2016.

Mississippi Power 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 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 Mississippi Power 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). Southern Company and Mississippi Power recorded pre-tax charges to income for revisions to the cost estimate above the cost cap of $365 million ($226 million after tax), $868 million ($536 million after tax), and $1.1 billion ($681 million after tax) in 2015, 2014, and 2013, respectively. The increases to the cost estimate in 2015 primarily reflect costs for the extension of the Kemper IGCC's projected in-service date through August 31, 2016, increased efforts related to scope modifications, additional labor costs in support of start-up and operational readiness activities, and system repairs and modifications after startup testing and commissioning activities identified necessary remediation of equipment installation, fabrication, and design issues, including the refractory lining inside the gasifiers; the lignite feed and dryer systems; and the syngas cooler vessels.

Any extension of the in-service date beyond August 31, 2016 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 August 31, 2016 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 $13 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 $2 million per month.

Mississippi Power's analysis of the time needed to complete the start-up and commissioning activities for the Kemper IGCC will continue until the remaining Kemper IGCC assets are placed in service. Further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, 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 for this first-of-a-kind technology (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). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company’s and Mississippi Power's statements of operations and these changes could be material.

In January 2013, Mississippi Power 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, Mississippi Power 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.

On February 12, 2015, the Mississippi Supreme Court (Court) issued its decision in the legal challenge to the 2013 MPSC Rate Order. The Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the 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 rates 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.

As a result of the 2015 Court decision, on July 10, 2015, Mississippi Power filed a request for interim rates with the Mississippi PSC which presented an alternative rate proposal (In-Service Asset Proposal) for consideration by the Mississippi PSC. The In-Service Asset Proposal was based upon the test period of June 2015 to May 2016, was designed to recover Mississippi Power'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, and was designed to collect approximately $159 million annually. On August 13, 2015, the Mississippi PSC approved the implementation of interim rates that became effective with the first billing cycle in September, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order) adopting in full a stipulation (the 2015 Stipulation) entered into between Mississippi Power and the Mississippi Public Utilities Staff regarding the In-Service Asset Proposal. Consistent with the 2015 Stipulation, the In-Service Asset Rate Order provides for retail rate recovery of an annual revenue requirement of approximately $126 million, based on Mississippi Power’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 during the test period. The In-Service Asset Rate Order also includes a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets.

With implementation of the new rate on December 17, 2015, the interim rates were terminated and Mississippi Power recorded a customer refund of approximately $11 million in December 2015 for the difference between the interim rates collected and the permanent rates. The refund is required to be completed by March 16, 2016.

Pursuant to the In-Service Asset Rate Order, Mississippi Power is required to file a subsequent rate request within 18 months. As part of the filing, Mississippi Power expects to request recovery of certain costs that the Mississippi PSC had excluded from the revenue requirement calculation.

On February 25, 2016, Greenleaf CO2 Solutions, LLC filed a notice of appeal of the In-Service Asset Rate Order with the Court. Mississippi Power believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on Southern Company's results of operations. The ultimate outcome of this matter cannot be determined at this time.

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. Mississippi Power expects 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.

In 2010 and as amended in 2012, Mississippi Power and SMEPA entered into an agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC. On May 20, 2015, SMEPA notified Mississippi Power that it was terminating the agreement. Mississippi Power had previously received a total of $275 million of deposits from SMEPA that were returned by Southern Company to SMEPA, with interest of approximately $26 million, on June 3, 2015, as a result of the termination, pursuant to its guarantee obligation. Subsequently, Mississippi Power issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures December 1, 2017. The In-Service Asset Proposal and the related rates approved by the Mississippi PSC excluded any costs associated with the 15% undivided interest. Mississippi Power continues to evaluate its alternatives with respect to its investment and the related costs associated with the 15% undivided interest.

Mississippi Power expects to seek additional rate relief to address recovery of the remaining Kemper IGCC assets. In addition to current estimated costs at December 31, 2015 of $6.63 billion, Mississippi Power anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Mississippi Power also expects the Mississippi PSC to apply operational parameters in connection with 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 Mississippi Power incurs additional costs to satisfy such parameters, there could be a material adverse impact on Mississippi Power's financial statements.

Mississippi Power has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide Denbury and Treetop with termination rights as Mississippi Power has not satisfied its contractual obligation to deliver captured CO_2 by May 11, 2015. Since May 11, 2015, Mississippi Power has been engaged in ongoing discussions with its off-takers regarding the status of the CO_2 delivery schedule as well as other issues related to the CO_2 agreements. As a result of discussions with Treetop, on August 3, 2015, Mississippi Power agreed to amend certain provisions of their agreement that do not affect pricing or minimum purchase quantities. Potential requirements imposed on CO_2 off-takers under the Clean Power Plan (if ultimately enacted in its current form, pending resolution of litigation) and the potential adverse financial impact of low oil prices on the off-takers increase the risk that the CO_2 contracts may be terminated or materially modified. Any termination or material modification of these agreements could result in a material reduction in Mississippi Power’s revenues to the extent Mississippi Power is not able to enter into other similar contractual arrangements. Additionally, if the contracts remain in place, sustained oil price reductions could result in significantly lower revenues than Mississippi Power forecasted to be available to offset customer rate impacts, which could have a material impact on Mississippi Power's financial statements.

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

FINANCIAL, ECONOMIC, AND MARKET RISKS

The generation operations and energy marketing operations of Southern Company, the traditional operating companies, and Southern Power are subject to risks, many of which are beyond their control, including changes in power prices and fuel costs, which may reduce Southern Company's, the traditional operating companies', and/or Southern Power's revenues and increase costs.

The generation operations and energy marketing operations of the Southern Company system are subject to changes in power prices and fuel costs, which could increase the cost of producing power or decrease the amount received from the sale of power. The market prices for these commodities may fluctuate significantly over relatively short periods of time. Among the factors that could influence power prices and fuel costs are:

- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels used in the generation facilities of the traditional operating companies and Southern Power, including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;
- liquidity in the general wholesale electricity market;
- weather conditions impacting demand for electricity;
- seasonality;
- transmission or transportation constraints, disruptions, or inefficiencies;
- availability of competitively priced alternative energy sources;

- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;
- the financial condition of market participants;
- the economy in the service territory, the nation, and worldwide, including the impact of economic conditions on demand for electricity and the demand for fuels;
- natural disasters, wars, embargos, acts of terrorism, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

Certain of these factors could increase the expenses of the traditional operating companies or Southern Power and Southern Company. For the traditional operating companies, such increases may not be fully recoverable through rates. Other of these factors could reduce the revenues of the traditional operating companies or Southern Power and Southern Company.

Historically, the traditional operating companies from time to time have experienced underrecovered fuel cost balances and may experience such balances in the future. While the traditional operating companies are generally authorized to recover fuel costs through fuel cost recovery clauses, recovery may be denied if costs are deemed to be imprudently incurred, and delays in the authorization of such recovery could negatively impact the cash flows of the affected traditional operating company and Southern Company.

Southern Company, the traditional operating companies, and Southern Power are subject to risks associated with a changing economic environment, customer behaviors, including increased energy conservation, and adoption patterns of technologies by the customers of the traditional operating companies and Southern Power.

The consumption and use of energy are fundamentally linked to economic activity. This relationship is affected over time by changes in the economy, customer behaviors, and technologies. Any economic downturn could negatively impact customer growth and usage per customer, thus reducing the sales of electricity and revenues. Additionally, any economic downturn or disruption of financial markets, both nationally and internationally, could negatively affect the financial stability of customers and counterparties of the traditional operating companies and Southern Power.

Outside of economic disruptions, changes in customer behaviors in response to energy efficiency programs, changing conditions and preferences or changes in the adoption of technologies could affect the relationship of economic activity to the consumption of electricity.

Both federal and state programs exist to influence how customers use energy, and several of the traditional operating companies have PSC mandates to promote energy efficiency. Conservation programs could impact the financial results of Southern Company, the traditional operating companies, and Southern Power in different ways. For example, if any traditional operating company is required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact on such traditional operating company and Southern Company. Customers could also voluntarily reduce their consumption of electricity in response to decreases in their disposable income, increases in energy prices, or individual conservation efforts.

In addition, the adoption of technology by customers can have both positive and negative impacts on sales. Many new technologies utilize less energy than in the past. However, new electric technologies such as electric vehicles can create additional demand. There can be no assurance that the Southern Company system's planning processes will appropriately estimate and incorporate the impacts of changes in customer behavior, state and federal programs, PSC mandates, and technology.

All of the factors discussed above could adversely affect Southern Company's, the traditional operating companies', and/or Southern Power's results of operations, financial condition, and liquidity.

The operating results of Southern Company, the traditional operating companies, and Southern Power are affected by weather conditions and may fluctuate on a seasonal and quarterly basis. In addition, significant weather events, such as hurricanes, tornadoes, floods, droughts, and winter storms, could result in substantial damage to or limit the operation of the properties of the traditional operating companies and/or Southern Power and could negatively impact results of operation, financial condition, and liquidity.

Electric power supply is generally a seasonal business. In many parts of the country, demand for power peaks during the summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power may fluctuate substantially on a seasonal basis. In addition, the traditional operating companies and Southern Power have historically sold less power when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net income, and available cash of Southern Company, the traditional operating companies, and/or Southern Power.

In addition, volatile or significant weather events could result in substantial damage to the transmission and distribution lines of the traditional operating companies and the generating facilities of the traditional operating companies and Southern Power. The traditional operating companies and Southern Power have significant investments in the Atlantic and Gulf Coast regions and Southern Power has wind investments in Oklahoma which could be subject to major storm activity. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities.

In the event a traditional operating company experiences any of these weather events or any natural disaster or other catastrophic event, recovery of costs in excess of reserves and insurance coverage is subject to the approval of its state PSC. Historically, the traditional operating companies from time to time have experienced deficits in their storm cost recovery reserve balances and may experience such deficits in the future. Any denial by the applicable state PSC or delay in recovery of any portion of such costs could have a material negative impact on a traditional operating company's and Southern Company's results of operations, financial condition, and liquidity.

In addition, damages resulting from significant weather events within the service territory of any traditional operating company or affecting Southern Power's customers may result in the loss of customers and reduced demand for electricity for extended periods. Any significant loss of customers or reduction in demand for electricity could have a material negative impact on a traditional operating company's or Southern Power's and Southern Company's results of operations, financial condition, and liquidity.

Southern Company may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay upstream dividends or repay funds to Southern Company.

Southern Company is a holding company and, as such, Southern Company has no operations of its own. Substantially all of Southern Company's consolidated assets are held by subsidiaries. Southern Company's ability to meet its financial obligations and to pay dividends on its common stock is primarily dependent on the net income and cash flows of its subsidiaries and their ability to pay upstream dividends or to repay funds to Southern Company. Prior to funding Southern Company, Southern Company's subsidiaries have regulatory restrictions and financial obligations that must be satisfied, including among others, debt service and preferred and preference stock dividends. Southern Company's subsidiaries are separate legal entities and have no obligation to provide Southern Company with funds. In addition, Southern Company may provide capital contributions or debt financing to subsidiaries under certain circumstances, which would reduce Southern Company’s funds available to meet its financial obligations and to pay dividends on its common stock.

A downgrade in the credit ratings of Southern Company, any of the traditional operating companies, or Southern Power could negatively affect their ability to access capital at reasonable costs and/or could require Southern Company, the traditional operating companies, or Southern Power to post collateral or replace certain indebtedness.

There are a number of factors that rating agencies evaluate to arrive at credit ratings for Southern Company, the traditional operating companies, and Southern Power, including capital structure, regulatory environment, the ability to cover liquidity requirements, and other commitments for capital. Southern Company, the traditional operating companies, and Southern Power could experience a downgrade in their ratings if any rating agency concludes that the level of business or financial risk of the industry or Southern Company, the traditional operating companies, or Southern Power has deteriorated. Changes in ratings methodologies by the agencies could also have a negative impact on credit ratings. If one or more rating agencies downgrade Southern Company, the traditional operating companies, or Southern Power, borrowing costs would increase, including automatic increases in interest rates under applicable term loans and credit facilities, the pool of investors and funding sources would likely decrease, and, particularly for any downgrade to below investment grade, significant collateral requirements may be triggered in a number of contracts. Any credit rating downgrades could require a traditional operating company or Southern Power to alter the mix of debt financing currently used, and could require the issuance of secured indebtedness and/or indebtedness with additional restrictive covenants.

Uncertainty in demand for power can result in lower earnings or higher costs. If demand for power falls short of expectations, it could result in potentially stranded assets. If demand for power exceeds expectations, it could result in increased costs for purchasing capacity in the open market or building additional generation and transmission facilities.

Southern Company, the traditional operating companies, and Southern Power each engage in a long-term planning process to estimate the optimal mix and timing of new generation assets required to serve future load obligations. This planning process must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation and associated transmission facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including regional economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional operating companies to adjust rates to recover the costs of new generation and associated transmission assets in a timely manner or at all, the traditional operating companies may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of additional capacity and the traditional operating companies' recovery in customers' rates. In addition, under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if market prices drop below original forecasts. Southern Power and/or the traditional operating companies may not be able to extend existing PPAs or to find new buyers for existing generation assets as existing PPAs expire, or they may be forced to market these assets at prices lower than originally intended. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and for Southern Company.

The traditional operating companies and Southern Power are currently obligated to supply power to retail customers and wholesale customers under long-term PPAs. At peak times, the demand for power required to meet this obligation could exceed the Southern Company system's available generation capacity. Market or competitive forces may require that the traditional operating companies or Southern Power purchase capacity on the open market or build additional generation and transmission facilities. Because regulators may not permit the traditional operating companies to pass all of these purchase or construction costs on to their customers, the traditional operating companies may not be able to recover some or all of these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of purchased or constructed capacity and the traditional operating companies' recovery in customers' rates. Under Southern Power's long-term fixed price PPAs, Southern Power would not have the ability to recover any of these costs. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and for Southern Company.

The businesses of Southern Company, the traditional operating companies, and Southern Power are dependent on their ability to successfully access funds through capital markets and financial institutions. The inability of Southern Company, any traditional operating company, or Southern Power to access funds may limit its ability to execute its business plan by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows.

Southern Company, the traditional operating companies, and Southern Power rely on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flow from their respective operations. If Southern Company, any traditional operating company, or Southern Power is not able to access capital at competitive rates or on favorable terms, its ability to implement its business plan will be limited by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows. In addition, Southern Company, the traditional operating companies, and Southern Power rely on committed bank lending agreements as back-up liquidity which allows them to access low cost money markets. Each of Southern Company, the traditional operating companies, and Southern Power believes that it will maintain sufficient access to these financial markets based upon current credit ratings. However, certain events or market disruptions may increase the cost of borrowing or adversely affect the ability to raise capital through the issuance of securities or other borrowing arrangements or the ability to secure committed bank lending agreements used as back-up sources of capital. Such disruptions could include:

- an economic downturn or uncertainty;
- bankruptcy or financial distress at an unrelated energy company, financial institution, or sovereign entity;
- capital markets volatility and disruption, either nationally or internationally;
- changes in tax policy such as dividend tax rates;
- market prices for electricity and gas;
- terrorist attacks or threatened attacks on Southern Company's facilities or unrelated energy companies' facilities;
- war or threat of war; or
- the overall health of the utility and financial institution industries.

Mississippi Power’s financial condition and its ability to obtain financing needed for normal business operations and completion of construction and start-up of the Kemper IGCC were adversely affected by (i) the return of approximately $301 million of interest bearing refundable deposits to SMEPA in June 2015 in connection with the termination of the APA; (ii) the required refund of approximately $371 million of rate collections, including associated carrying costs, and the termination of those rates; and (iii) the required recapture of Phase II tax credits. Mississippi Power expects to refinance its 2016 debt maturities with bank term loans. Mississippi Power intends to utilize operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company to fund the remainder of Mississippi Power’s capital needs.

In addition, Georgia Power’s ability to make future borrowings through its term loan credit facility with the Federal Financing Bank is subject to the satisfaction of customary conditions, as well as certification of compliance with the requirements of the loan guarantee program under Title XVII of the Energy Policy Act of 2005, including accuracy of project-related representations and warranties, delivery of updated project-related information and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program.

Volatility in the securities markets, interest rates, and other factors could substantially increase defined benefit pension and other postretirement plan costs and the costs of nuclear decommissioning.

The costs of providing pension and other postretirement benefit plans are dependent on a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plan, changes in actuarial assumptions, future government regulation, changes in life expectancy, and the frequency and amount of the Southern Company system's required or voluntary contributions made to the plans. Changes in actuarial assumptions and differences between the assumptions and actual values, as well as a significant decline in the value of investments that fund the pension and other postretirement plans, if not offset or mitigated by a decline in plan liabilities, could increase pension and other postretirement expense, and the Southern Company system could be required from time to time to fund the pension plan with significant amounts of cash. Such cash funding obligations could have a material impact on liquidity by reducing cash flows and could negatively affect results of operations. Additionally, Alabama Power and Georgia Power each hold significant assets in their nuclear decommissioning trusts to satisfy obligations to decommission Alabama Power's and Georgia Power's nuclear plants. The rate of return on assets held in those trusts can significantly impact both the costs of decommissioning and the funding requirements for the trusts.

Southern Company, the traditional operating companies, and Southern Power are subject to risks associated with their ability to obtain adequate insurance at acceptable costs.

The financial condition of some insurance companies, the threat of terrorism, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that Southern Company, the traditional operating companies, Southern Power, and their respective competitors typically insure against may decrease, and the insurance that Southern Company, the traditional operating companies, and Southern Power are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, there is no guarantee that the insurance policies maintained by the Southern Company, the traditional operating companies, and Southern Power will cover all of the potential exposures or the actual amount of loss incurred.

Any losses not covered by insurance, or any increases in the cost of applicable insurance, could adversely affect the results of operations, cash flows, or financial condition of Southern Company, the traditional operating companies, or Southern Power.

The use of derivative contracts by Southern Company and its subsidiaries in the normal course of business could result in financial losses that negatively impact the net income of Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, use derivative instruments, such as swaps, options, futures, and forwards, to manage their commodity and interest rate exposures and, to a lesser extent, engage in limited trading activities. Southern Company and its subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, limits, and procedures. These risk management policies, limits, and procedures might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, derivative contracts entered for hedging purposes might not off-set the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. The factors used in the valuation of these instruments become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

ACQUISITION RISKS

Acquisitions and dispositions may not result in anticipated benefits and may present risks not originally contemplated, which may have a material adverse effect on the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.

Southern Company and its subsidiaries have made significant acquisitions and dispositions in the past and may in the future make additional acquisitions and dispositions. Southern Power, in particular, continually seeks opportunities to create value through various transactions, including acquisitions or sales of assets.

Southern Company and its subsidiaries may face significant competition for acquisition opportunities and there can be no assurance that anticipated acquisitions will be completed on acceptable terms or at all. In addition, these transactions are intended to, but may not, result in the generation of cash or income, the realization of savings, the creation of efficiencies, or the reduction of risk. These transactions may also affect the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.

These transactions also involve risks, including:

- any acquisitions may not result in an increase in income or provide an adequate return on capital or other anticipated benefits;
- any acquisitions may not be successfully integrated into the acquiring company’s operations and internal controls processes;
- the due diligence conducted prior to an acquisition may not uncover situations that could result in financial or legal exposure or the acquiring company may not appropriately evaluate the likelihood or quantify the exposure from identified risks;
- any disposition may result in decreased earnings, revenue, or cash flow;
- use of cash for acquisitions may adversely affect cash available for capital expenditures and other uses; or
- any dispositions, investments, or acquisitions could have a material adverse effect on the liquidity, results of operations, or financial condition of Southern Company or its subsidiaries.

Southern Company and AGL Resources may encounter difficulties in satisfying the conditions for the completion of the Merger, including receipt of all required regulatory approvals, which could delay the completion of the Merger or impose conditions that could have a material adverse effect on the combined company or that could cause either party to abandon the Merger.

Consummation of the Merger remains subject to the satisfaction or waiver of certain closing conditions, including, among others, (i) the approval of the California Public Utilities Commission, Georgia PSC, Illinois Commerce Commission, and Maryland PSC, New Jersey Board of Public Utilities, and other approvals required under applicable state laws, and the approval of the Federal Communications Commission (FCC) for the transfer of control over the FCC licenses of certain subsidiaries of AGL Resources, (ii) the absence of a judgment, order, decision, injunction, ruling, or other finding or agency requirement of a governmental entity prohibiting the consummation of the Merger, and (iii) other customary closing conditions, including (a) subject to certain materiality qualifiers, the accuracy of each party's representations and warranties and (b) each party's performance in all material respects of its obligations under the Merger Agreement.

Southern Company completed the required state regulatory filings in the fourth quarter 2015 and the required FCC filings in February 2016. On February 24, 2016, a stipulation and settlement agreement between Southern Company, AGL Resources, the Maryland PSC Staff, and the Maryland Office of People's Counsel was filed with the Maryland PSC. The proposed settlement remains subject to the approval of the Maryland PSC. Additionally, Southern Company received the approval of the Virginia State Corporation Commission in February 2016.

These governmental entities may decline to approve the Merger or may impose conditions on the completion, or require changes to the terms, of the Merger, including restrictions or conditions on the business, operations, or financial performance of the combined company following the Merger.

Satisfying the conditions to completion of the Merger may take longer, and could cost more, than Southern Company expects. Any delay in completing the Merger or any additional conditions imposed in order to complete the Merger may materially adversely affect the benefits that Southern Company expects to achieve from the Merger and the integration of the companies' respective businesses.

In addition, conditions to the completion of the Merger may fail to be satisfied. Subject to certain limitations, either party may terminate the Merger Agreement if the Merger is not consummated by August 23, 2016, which date may be extended by either party to February 23, 2017 if, on August 23, 2016, all conditions to closing other than those relating to (i) regulatory approvals and (ii) the absence of legal restraints preventing consummation of the Merger (to the extent relating to regulatory approvals) have been satisfied.

Any delay in completing the Merger, conditions imposed by governmental entities, or failure to complete the Merger could have a material adverse effect on the financial condition, net income, and cash flows of Southern Company.

Failure to complete the Merger could negatively impact Southern Company's stock price and Southern Company's future business and financial results.

Completion of the Merger is not assured and is subject to risks, including the risks that approval of the transaction by governmental entities will not be obtained or that certain other closing conditions will not be satisfied. If the Merger is not completed, Southern Company's ongoing businesses and financial results may be adversely affected and Southern Company will be subject to a number of risks, including the following:

- Southern Company will be required to pay significant costs relating to the Merger, including legal, accounting, and financial advisory costs, whether or not the Merger is completed;
- matters relating to the Merger (including integration planning) may require substantial commitments of time and resources by Southern Company management, which could otherwise have been devoted to other opportunities that may have been beneficial to Southern Company; and
- negative publicity and a negative impression of Southern Company in the investment community.

The occurrence of any of these events, individually or in combination, could cause the share price of Southern Company to decline if and to the extent that the current market prices reflect an assumption by the market that the Merger will be completed.

If completed, the Merger may not achieve its intended results.

Southern Company entered into the Merger Agreement with the expectation that the Merger would result in various benefits. Achieving the anticipated benefits of the Merger is subject to a number of uncertainties, including whether the business of AGL Resources is integrated in an efficient and effective manner, conditions imposed on the Merger by federal and state public utility, antitrust, and other regulatory authorities prior to approval, general market and economic conditions, and general competitive factors in the marketplace. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by the combined company, and diversion of management's time and energy and could have an adverse effect on the combined company's financial condition, net income, and cash flows.

The Southern Company system will be subject to business uncertainties while the Merger is pending that could adversely affect Southern Company's financial results.

Uncertainty about the effect of the Merger on employees, suppliers, and customers of the Southern Company system may have an adverse effect on Southern Company. These uncertainties may impair the Southern Company system's ability to attract, retain, and motivate key personnel until the Merger is completed and for a period of time thereafter and could cause customers, suppliers, and others that deal with the Southern Company system to seek to change existing business relationships.

Employee retention and recruitment may be particularly challenging prior to the completion of the Merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If key employees depart or fail to accept employment with the Southern Company system because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, Southern Company's financial results could be adversely affected.

The pursuit of the Merger and the preparation for the integration of AGL Resources into the Southern Company system may place a significant burden on management and internal resources. The diversion of management attention away from day-to-day business concerns and any difficulties encountered in the transition and integration process could adversely affect Southern Company's financial condition, net income, and cash flows.

Southern Company is obligated to complete the Merger whether or not it has obtained the required financing.

Southern Company intends to initially fund the cash consideration for the Merger using a mix of debt and equity. Southern Company finances its capital needs on a portfolio basis and expects to issue approximately $8.0 billion in debt prior to closing the Merger and approximately $1.2 billion in equity during 2016. This capital is expected to provide funding for the Merger, Southern Power growth opportunities, and other Southern Company system capital projects. In addition, Southern Company entered into the $8.1 billion Bridge Agreement on September 30, 2015 to provide financing for the Merger in the event long-term financing is not available. The Bridge Agreement is subject to various conditions contained in the Bridge Agreement and the issuance of long-term debt and equity sales to finance the Merger will be subject to future market conditions.

Following the Merger, stockholders of Southern Company will own equity interests in a company whose subsidiary owns and operates a natural gas business.

AGL Resources is an energy services holding company whose primary business is the distribution of natural gas through natural gas distribution utilities. AGL Resources is involved in several other businesses that are mainly related and complementary to its primary business including: retail operations including the provision of natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice, wholesale services including natural gas storage, gas pipeline arbitrage, and natural gas asset management and/or related logistics services, and midstream operations including high deliverability natural gas storage facilities and select pipelines. As a result, the combined company will be subject to various risks to which Southern Company is not currently subject, including risks related to transporting and storing natural gas. As stockholders of the combined company following the Merger, Southern Company stockholders may be adversely affected by these risks.

Southern Company expects to record goodwill that could become impaired and adversely affect its operating results.

In accordance with GAAP, the Merger will be accounted for using the acquisition method of accounting whereby the assets acquired and liabilities assumed are recognized at fair value as of the acquisition date. The excess of the purchase price over the fair values of AGL Resources' assets and liabilities will be recorded as goodwill.

The amount of goodwill, which is expected to be material, will be allocated to the appropriate reporting units of the combined company. Southern Company is required to assess goodwill for impairment at least annually by comparing the fair value of reporting units to the carrying value of those reporting units. To the extent the carrying value of any of those reporting units is greater than the fair value, a second step comparing the implied fair value of goodwill to the carrying amount would be required to determine if the goodwill is impaired. Such a potential impairment could result in a material charge that would have a material impact on Southern Company's future operating results and consolidated balance sheet.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES

Electric Properties

The traditional op erating companies, Southern Power, and SEGCO, at December 31, 2015, owned and/or operated 33 hydroelectric generating stations, 31 fossil fuel generating stations, three nuclear generating stations, 13 combined cycle/cogeneration stations, 16 solar facilities, one wind facility, one biomass facility, and one landfill gas facility. The amounts of capacity for each company, as of December 31, 2015, are shown in the table below.

Generating Station	Location	Nameplate Capacity (1)	
		(KWs)	
FOSSIL STEAM			
Gadsden	Gadsden, AL	120,000	
Gorgas	Jasper, AL	1,021,250	(2)
Barry	Mobile, AL	1,300,000	(2)
Greene County	Demopolis, AL	300,000	(3)
Gaston Unit 5	Wilsonville, AL	880,000	
Miller	Birmingham, AL	2,532,288	(4)
Alabama Power Total		6,153,538	
Bowen	Cartersville, GA	3,160,000	
Hammond	Rome, GA	800,000	
McIntosh	Effingham County, GA	163,117	
Mitchell	Albany, GA	125,000	(5)
Scherer	Macon, GA	750,924	(6)
Wansley	Carrollton, GA	925,550	(7)
Yates	Newnan, GA	700,000	
Georgia Power Total		6,624,591	
Crist	Pensacola, FL	970,000	
Daniel	Pascagoula, MS	500,000	(8)
Lansing Smith	Panama City, FL	305,000	(9)
Scherer Unit 3	Macon, GA	204,500	(6)
Gulf Power Total		1,979,500	
Daniel	Pascagoula, MS	500,000	(8)
Greene County	Demopolis, AL	200,000	(3)
Sweatt	Meridian, MS	80,000	(10)
Watson	Gulfport, MS	862,000	(10)
Mississippi Power Total		1,642,000	
Gaston Units 1-4	Wilsonville, AL		
SEGCO Total		1,000,000	(11)
Total Fossil Steam		17,399,629	
IGCC			
Kemper County/Ratcliffe	Kemper County, MS		(12)
Mississippi Power Total		622,906	

Generating Station	Location	Nameplate Capacity (1)	
NUCLEAR STEAM			
Farley	Dothan, AL		
Alabama Power Total		1,720,000	
Hatch	Baxley, GA	899,612	(13)
Vogtle Units 1 and 2	Augusta, GA	1,060,240	(14)
Georgia Power Total		1,959,852	
Total Nuclear Steam		3,679,852	
COMBUSTION TURBINES			
Greene County	Demopolis, AL		
Alabama Power Total		720,000	
Boulevard	Savannah, GA	19,700	
Intercession City	Intercession City, FL	47,667	(5)
Kraft	Port Wentworth, GA	22,000	(5)
McDonough Unit 3	Atlanta, GA	78,800	
McIntosh Units 1 through 8	Effingham County, GA	640,000	
McManus	Brunswick, GA	481,700	
Mitchell	Albany, GA	78,800	(5)
Robins	Warner Robins, GA	158,400	
Wansley	Carrollton, GA	26,322	(7)
Wilson	Augusta, GA	354,100	
Georgia Power Total		1,907,489	
Lansing Smith Unit A	Panama City, FL	39,400	
Pea Ridge Units 1 through 3	Pea Ridge, FL	15,000	
Gulf Power Total		54,400	
Chevron Cogenerating Station	Pascagoula, MS	147,292	(15)
Sweatt	Meridian, MS	39,400	
Watson	Gulfport, MS	39,360	
Mississippi Power Total		226,052	
Addison (formerly West Georgia)	Thomaston, GA	668,800	
Cleveland County	Cleveland County, NC	720,000	
Dahlberg	Jackson County, GA	756,000	
Oleander	Cocoa, FL	791,301	
Rowan	Salisbury, NC	455,250	
Southern Power Total		3,391,351	
Gaston **(SEGCO)**	Wilsonville, AL	19,680	(11)
Total Combustion Turbines		6,318,972	
COGENERATION			
Washington County	Washington County, AL	123,428	
GE Plastics Project	Burkeville, AL	104,800	
Theodore	Theodore, AL	236,418	
Total Cogeneration		464,646	

Generating Station	Location	Nameplate Capacity (1)	
COMBINED CYCLE			
Barry	Mobile, AL		
Alabama Power Total		1,070,424	
McIntosh Units 10&11	Effingham County, GA	1,318,920	
McDonough-Atkinson Units 4 through 6	Atlanta, GA	2,520,000	
Georgia Power Total		3,838,920	
Smith	Lynn Haven, FL		
Gulf Power Total		545,500	
Daniel	Pascagoula, MS		
Mississippi Power Total		1,070,424	
Franklin	Smiths, AL	1,857,820	
Harris	Autaugaville, AL	1,318,920	
Rowan	Salisbury, NC	530,550	
Stanton Unit A	Orlando, FL	428,649	(16)
Wansley	Carrollton, GA	1,073,000	
Southern Power Total		5,208,939	
Total Combined Cycle		11,734,207	
HYDROELECTRIC FACILITIES			
Bankhead	Holt, AL	53,985	
Bouldin	Wetumpka, AL	225,000	
Harris	Wedowee, AL	132,000	
Henry	Ohatchee, AL	72,900	
Holt	Holt, AL	46,944	
Jordan	Wetumpka, AL	100,000	
Lay	Clanton, AL	177,000	
Lewis Smith	Jasper, AL	157,500	
Logan Martin	Vincent, AL	135,000	
Martin	Dadeville, AL	182,000	
Mitchell	Verbena, AL	170,000	
Thurlow	Tallassee, AL	81,000	
Weiss	Leesburg, AL	87,750	
Yates	Tallassee, AL	47,000	
Alabama Power Total		1,668,079	
Bartletts Ferry	Columbus, GA	173,000	
Goat Rock	Columbus, GA	38,600	
Lloyd Shoals	Jackson, GA	14,400	
Morgan Falls	Atlanta, GA	16,800	
North Highlands	Columbus, GA	29,600	
Oliver Dam	Columbus, GA	60,000	
Rocky Mountain	Rome, GA	215,256	(17)
Sinclair Dam	Milledgeville, GA	45,000	
Tallulah Falls	Clayton, GA	72,000	
Terrora	Clayton, GA	16,000	
Tugalo	Clayton, GA	45,000	
Wallace Dam	Eatonton, GA	321,300	
Yonah	Toccoa, GA	22,500	
6 Other Plants	Various Georgia Cities	18,080	

Generating Station	Location	Nameplate Capacity (1)	
Georgia Power Total		1,087,536	
Total Hydroelectric Facilities		2,755,615	
RENEWABLE SOURCES:			
SOLAR FACILITIES			
Fort Benning	Columbus, GA	30,000	
Dalton	Dalton, GA	6,305	
Georgia Power Total		36,305	
Adobe	Kern County, CA	20,000	
Apex	North Las Vegas, NV	20,000	
Campo Verde	Imperial County, CA	147,420	
Cimarron	Springer, NM	30,640	
Decatur County	Decatur County, GA	20,000	
Decatur Parkway	Decatur County, GA	84,000	
Desert Stateline	San Bernadino County, CA	110,120	(18)
Granville	Oxford, NC	2,500	
Imperial Valley	Imperial County, CA	163,200	
Lost Hills - Blackwell	Kern County, CA	33,440	
Macho Springs	Luna County, NM	55,000	
Morelos del Sol	Kern County, CA	15,000	
North Star	Fresno County, CA	61,600	
Spectrum	Clark County, NV	30,240	
Southern Power Total		793,160	(19)
Total Solar		829,465	
WIND FACILITY			
Kay Wind	Kay County, OK		
Southern Power Total		299,000	
LANDFILL GAS FACILITY			
Perdido	Escambia County, FL		
Gulf Power Total		3,200	
BIOMASS FACILITY			
Nacogdoches	Sacul, TX		
Southern Power Total		115,500	
Total Generating Capacity		44,222,992	

Notes:

(1) See "Jointly-Owned Facilities" herein for additional information.

(2) In April 2015, as part of its environmental compliance strategy, Alabama Power retired Plant Gorgas Units 6 and 7 (200MWs). Additionally, in April 2015, Alabama Power ceased using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. In August 2015, Alabama Power retired Plant Barry Unit 3 (225 MWs) and it is no longer available for generation. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Alabama Power – Environmental Accounting Order" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Environmental Accounting Order" of Alabama Power in Item 7 herein. See also Note 3 to the financial statements of Southern Company and Alabama Power under "Retail Regulatory Matters – Alabama Power – Environmental Accounting Order" and "Retail Regulatory – Environmental Accounting Order," respectively, in Item 8 herein.

(3) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively. Alabama Power and Mississippi Power expect to cease using coal and begin operating these units solely on natural gas by April 2016. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Alabama Power – Environmental Accounting Order" of Southern Company, MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters – Environmental Accounting Order" of Alabama Power, and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Environmental Compliance Overview Plan" of Mississippi Power in Item 7 herein. See also Note 3 to the financial statements of Southern Company, Alabama Power, and Mississippi Power under "Retail Regulatory Matters – Alabama Power – Environmental Accounting Order," "Retail Regulatory Matters – Environmental Accounting Order," and "Retail Regulatory Matters – Environmental Compliance Overview Plan," respectively, in Item 8 herein.

(4) Capacity shown is Alabama Power's portion (91.84%) of total plant capacity.

(5) On January 29, 2016, Georgia Power filed its triennial IRP (2016 IRP). The filing included a request to decertify Plant Mitchell Units 3, 4A, and 4B (217MWs) and Plant Kraft Unit 1 (17 MWs) upon approval of the 2016 IRP. The 2016 IRP also reflects that Georgia Power exercised its contractual option to sell its ownership interest in the Intercession City unit to Duke Energy Florida, Inc. contingent upon regulatory approvals. The ultimate outcome of this matter cannot be determined at this time. Capacity shown represents 33% of the total plant capacity of 143,000 KWs. Georgia Power owns a 33% interest in the unit with 100% use of the unit from June through September. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Georgia Power – Integrated Resource Plan" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Integrated Resource Plan" of Georgia Power in Item 7 herein. See also Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Integrated Resource Plan" and "Retail Regulatory – Integrated Resource Plan," respectively, in Item 8 herein.

(6) Capacity shown for Georgia Power is 8.4% of Units 1 and 2 and 75% of Unit 3. Capacity shown for Gulf Power is 25% of Unit 3.

(7) Capacity shown is Georgia Power's portion (53.5%) of total plant capacity.

(8) Represents 50% of Plant Daniel Units 1 and 2, which are owned as tenants in common by Gulf Power and Mississippi Power.

(9) Gulf Power intends to retire Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016.

(10) Mississippi Power agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source at Plant Sweatt Units 1 and 2 (80 MWs) by December 2018. Mississippi Power also ceased burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and began operating those units solely on natural gas on April 16, 2015.

(11) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information.

(12) Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service using natural gas in August 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities. The Kemper IGCC is expected to have an output capacity of 582 MW.

(13) Capacity shown is Georgia Power's portion (50.1%) of total plant capacity.

(14) Capacity shown is Georgia Power's portion (45.7%) of total plant capacity.

(15) Generation is dedicated to a single industrial customer.

(16) Capacity shown is Southern Power's portion (65%) of total plant capacity.

(17) Capacity shown is Georgia Power's portion (25.4%) of total plant capacity. OPC operates the plant.

(18) The first three phases (110 MW) were placed in service in December 2015. Phases four and five were placed in service in January and February 2016, respectively. The remaining three phases are expected to be placed in service during 2016, bringing the facility's total capacity to approximately 300 MW.

(19) Southern Power total solar capacity shown is 100% of the nameplate capacity for each facility. When taking into consideration Southern Power's 90% equity interest in STR and 51% equity interest in SRP's seven partnerships, Southern Power's equity portion of the total nameplate capacity from all generating sources is 9,595 MW. See Note 2 to the financial statements of Southern Power in Item 8 herein and Note 12 to the financial statements of Southern Company under "Southern Power" in Item 8 herein for additional information.

Except as discussed below under "Titles to Property," the principal plants and other important units of the traditional operating companies, Southern Power, and SEGCO are owned in fee by the respective companies. It is the opinion of management of each such company that its operating properties are adequately maintained and are substantially in good operating condition.

Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States Louisiana, LLC. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States Louisiana, LLC is paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2015, the unamortized portion of this cost was approximately $14 million.

In conjunction with the Kemper IGCC, Mississippi Power owns a lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site in Kemper County. The mine, operated by North American Coal Corporation, started commercial operation in June 2013 with the capital cost of the mine and equipment totaling approximately $313 million as of December 31, 2015. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" in Item 8 herein for additional information on the lignite mine.

In 2015, the maximum demand on the traditional operating companies, Southern Power, and SEGCO was 36,794,000 KWs and occurred on January 8, 2015. The all-time maximum demand of 38,777,000 KWs on the traditional operating companies, Southern Power, and SEGCO occurred on August 22, 2007. These amounts exclude demand served by capacity retained by MEAG Power, OPC, and SEPA. The reserve margin for the traditional operating companies, Southern Power, and SEGCO in 2015 was 33.2%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information.

Jointly-Owned Facilities

Alabama Power, Georgia Power, and Southern Power at December 31, 2015 had undivided interests in certain generating plants and other related facilities with non-affiliated parties. The percentages of ownership of the total plant or facility are as follows:

		Percentage Ownership										
	Total Capacity	Alabama Power	Power South	Georgia Power	OPC	MEAG Power	Dalton	Duke Energy Florida	Southern Power	OUC	FMPA	KUA
	(MWs)											
Plant Miller Units 1 and 2	1,320	91.8%	8.2%	—%	—%	—%	—%	—%	—%	—%	—%	—%
Plant Hatch	1,796	—	—	50.1	30.0	17.7	2.2	—	—	—	—	—
Plant Vogtle Units 1 and 2	2,320	—	—	45.7	30.0	22.7	1.6	—	—	—	—	—
Plant Scherer Units 1 and 2	1,636	—	—	8.4	60.0	30.2	1.4	—	—	—	—	—
Plant Wansley	1,779	—	—	53.5	30.0	15.1	1.4	—	—	—	—	—
Rocky Mountain	848	—	—	25.4	74.6	—	—	—	—	—	—	—
Intercession City, FL*	143	—	—	33.3	—	—	—	66.7	—	—	—	—
Plant Stanton A	660	—	—	—	—	—	—	—	65.0	28.0	3.5	3.5

* Subsequent to December 31, 2015, Georgia Power exercised its contractual option to sell its ownership interest to Duke Energy Florida, Inc. contingent on regulatory approvals. The ultimate outcome of this matter cannot be determined at this time.

Alabama Power and Georgia Power have contracted to operate and maintain the respective units in which each has an interest (other than Rocky Mountain and Intercession City) as agent for the joint owners. SCS provides operation and maintenance services for Plant Stanton A. Southern Nuclear operates and provides services to Alabama Power's and Georgia Power's nuclear plants.

In addition, Georgia Power has commitments regarding a portion of a 5% interest in Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the later of retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether any capacity is available. The energy cost is a function of each unit's variable operating costs. Except for the portion of the capacity payments related to the Georgia PSC's disallowances of Plant Vogtle Units 1 and 2 costs, the cost of such capacity and energy is included in purchased power from non-affiliates in Georgia Power's statements of income in Item 8 herein. Also see Note 7 to the financial statements of Georgia Power under "Commitments – Fuel and Purchased Power Agreements" in Item 8 herein for additional information.

Georgia Power is currently constructing Plant Vogtle Units 3 and 4 which will be jointly owned by Georgia Power, Dalton, OPC, and MEAG Power (with each owner holding the same undivided ownership interest as shown in the table above with respect to Plant Vogtle Units 1 and 2). See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein.

Titles to Property

The traditional operating companies', Southern Power's, and SEGCO's interests in the principal plants (other than certain pollution control facilities and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the (1) liens pursuant to pollution control revenue bonds of Gulf Power on specific pollution control facilities at Plant Daniel, (2) liens pursuant to the assumption of debt obligations by Mississippi Power in connection with the acquisition of Plant Daniel Units 3 and 4, (3) liens associated with Georgia Power’s reimbursement obligations to the DOE under its loan guarantee, which are secured by a first priority lien on (a) Georgia Power’s 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (b) Georgia Power’s rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4, and (4) liens associated with credit agreements entered into by RE Tranquillity LLC, RE Roserock LLC, and RE Garland Holdings LLC, indirect subsidiaries of Southern Power Company. See Note 6 to the financial statements of Southern Company, Georgia Power, Gulf Power, and Mississippi Power under "Assets Subject to Lien," Note 6 to the financial statements of Southern Company and Georgia Power under "DOE Loan Guarantee Borrowings," Note 6 to the financial statements of Southern Company and Mississippi Power under "Plant Daniel Revenue Bonds," and Note 6 to the financial statements of Southern Power Company under "Bank Credit Arrangements – Subsidiary Facilities" in Item 8 herein for additional information. The traditional operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines, steam heating mains, and gas pipelines are constructed principally on rights-of-way, which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements. In addition, certain of the renewable generating facilities occupy or use real property that is not owned, primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental entities.

Item 3. LEGAL PROCEEDINGS

(1) Georgia Power et al. v. Westinghouse and Stone & Webster (United States District Court for the Southern District of Georgia Augusta Division)

Stone & Webster and Westinghouse v. Georgia Power et al. (United States District Court for the District of Columbia)

See Note 3 to the financial statements of Southern Company and Georgia Power under "Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein for information.

(2) Environmental Remediation

See Note 3 to the financial statements of Southern Company, Georgia Power, and Gulf Power under "Environmental Matters – Environmental Remediation" in Item 8 herein for information related to environmental remediation.

See Note 3 to the financial statements of each registrant in Item 8 herein for descriptions of additional legal and administrative proceedings discussed therein.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF SOUTHERN COMPANY

(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2015.

Thomas A. Fanning
Chairman, President, Chief Executive Officer, and Director
Age 58
Elected in 2003. Chairman, Chief Executive Officer, and Director since December 2010 and President since August 2010.

Art P. Beattie
Executive Vice President and Chief Financial Officer
Age 61
Elected in 2010. Executive Vice President and Chief Financial Officer since August 2010.

W. Paul Bowers
Executive Vice President
Age 59
Elected in 2001. Executive Vice President since February 2008 and Chief Executive Officer, President, and Director of Georgia Power since January 2011. Chairman of Georgia Power's Board of Directors since May 2014.

S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer of Gulf Power
Age 46
Elected in 2012. Elected Chairman in July 2015 and President, Chief Executive Officer, and Director of Gulf Power since July 2012. Previously served as Senior Vice President and Chief Production Officer of Georgia Power from August 2010 through June 2012.

Mark A. Crosswhite
Executive Vice President
Age 53
Elected in 2010. Executive Vice President since December 2010 and President, Chief Executive Officer, and Director of Alabama Power since March 2014. Chairman of Alabama Power's Board of Directors since May 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 through February 2014 and President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012.

Kimberly S. Greene
Executive Vice President
Age 49
Elected in 2013. Executive Vice President and Chief Operating Officer since March 2014. Previously served as President and Chief Executive Officer of SCS from April 2013 to February 2014. Before rejoining Southern Company, Ms. Greene previously served at Tennessee Valley Authority in a number of positions, most recently as Executive Vice President and Chief Generation Officer from 2011 through April 2013, and Group President of Strategy and External Relations from 2010 through 2011.

James Y. Kerr II
Executive Vice President and General Counsel
Age 51
Elected in 2014. Before joining Southern Company, Mr. Kerr was a partner with McGuireWoods LLP and a senior advisor at McGuireWoods Consulting LLC from 2008 through February 2014.

Stephen E. Kuczynski
President and Chief Executive Officer of Southern Nuclear
Age 53
Elected in 2011. President and Chief Executive Officer of Southern Nuclear since July 2011. Before joining Southern Company, Mr. Kuczynski served at Exelon Corporation as the Senior Vice President of Engineering and Technical Services for Exelon Nuclear from February 2009 to June 2011.

Mark S. Lantrip
Executive Vice President
Age 61
Elected in 2014. President and Chief Executive Officer of SCS since March 2014. Previously served as Treasurer of Southern Company from October 2007 to February 2014 and Executive Vice President of SCS from November 2010 to March 2014.

Anthony L. Wilson
President and Chief Executive Officer of Mississippi Power
Age 51
Elected in 2015. President of Mississippi Power since October 2015 and Chief Executive Officer and Director since January 2016. Previously served as Executive Vice President of Mississippi Power from May 2015 to October 2015, Executive Vice President of Georgia Power from January 2012 to May 2015, and Vice President of Georgia Power from February 2007 to December 2011.

Christopher C. Womack
Executive Vice President
Age 57
Elected in 2008. Executive Vice President and President of External Affairs since January 2009.

The officers of Southern Company were elected at the first meeting of the directors following the last annual meeting of stockholders held on May 27, 2015, for a term of one year or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF ALABAMA POWER

(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2015.

Mark A. Crosswhite
Chairman, President, Chief Executive Officer, and Director
Age 53
Elected in 2014. President, Chief Executive Officer, and Director since March 1, 2014. Chairman since May 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 through February 2014 and President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012.

Greg J. Barker (1)
Executive Vice President
Age 52
Elected in 2016. Executive Vice President for Customer Services since February 22, 2016. Previously served as Senior Vice President of Marketing and Economic Development from April 2012 to February 2016 and Senior Vice President of Business Development and Customer Support from July 2010 to April 2012.

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
Age 56
Elected in 2010. Executive Vice President, Chief Financial Officer, and Treasurer since August 2010.

Zeke W. Smith
Executive Vice President
Age 56
Elected in 2010. Executive Vice President of External Affairs since November 2010.

Steven R. Spencer (1)
Executive Vice President
Age 60
Elected in 2001. Executive Vice President of the Customer Service Organization since February 2008.

James P. Heilbron
Senior Vice President and Senior Production Officer
Age 44
Elected in 2013. Senior Vice President and Senior Production Officer since March 2013. Previously served as Senior Vice President and Senior Production Officer of Southern Power Company from July 2010 to February 2013.

(1) On February 17, 2016, Mr. Spencer resigned the role of Executive Vice President, effective April 1, 2016. Mr. Greg Barker was elected to the role of Executive Vice President for Customer Services, effective February 22, 2016.

The officers of Alabama Power were elected for at the meeting of the directors held on April 24, 2015 for a term of one year or until their successors are elected and have qualified, except for Mr. Barker whose election as Executive Vice President was effective February 22, 2016.

EXECUTIVE OFFICERS OF GEORGIA POWER

(Identification of executive officers of Georgia Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2015.

W. Paul Bowers
Chairman, President, Chief Executive Officer, and Director
Age 59
Elected in 2010. Chief Executive Officer, President, and Director since December 2010 and Chief Operating Officer of Georgia Power from August 2010 to December 2010. Chairman of Georgia Power's Board of Directors since May 2014.

W. Craig Barrs
Executive Vice President
Age 58
Elected in 2008. Executive Vice President of Customer Service and Operations since May 2015. Previously served as Executive Vice President of External Affairs from January 2010 to May 2015.

W. Ron Hinson
Executive Vice President, Chief Financial Officer, Treasurer, and Corporate Secretary
Age 59
Elected in 2013. Executive Vice President, Chief Financial Officer, and Treasurer since March 2013 and Corporate Secretary and Chief Compliance Officer since January 2016. Also, served as Comptroller from March 2013 until January 2014. Previously served as Comptroller and Chief Accounting Officer of Southern Company, as well as Senior Vice President and Comptroller of SCS from March 2006 to March 2013.

Christopher P. Cummiskey
Executive Vice President
Age 41
Elected in 2015. Executive Vice President of External Affairs since May 2015. Previously served as Chief Commercial Officer of Southern Power from October 2013 to May 2015 and Commissioner of the Georgia Department of Economic Development from January 2011 to October 2013.

John L. Pemberton
Senior Vice President and Senior Production Officer
Age 47
Elected in 2012. Senior Vice President and Senior Production Officer since July 2012. Previously served as Senior Vice President and General Counsel for SCS and Southern Nuclear from June 2010 to July 2012.

The officers of Georgia Power were elected at the meeting of the directors held on May 20, 2015 for a term of one year or until their successors are elected and have qualified, except for Mr. Hinson, whose election as Corporate Secretary was effective January 1, 2016.

EXECUTIVE OFFICERS OF MISSISSIPPI POWER

(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2015.

Anthony L. Wilson
President, Chief Executive Officer, and Director
Age 51
Elected in 2015. President since October 2015 and Chief Executive Officer and Director since January 2016. Previously served as Executive Vice President from May 2015 to October 2015, Executive Vice President of Georgia Power from January 2012 to May 2015, and Vice President of Georgia Power from February 2007 to December 2011.

John W. Atherton
Vice President
Age 55
Elected in 2004. Vice President of Corporate Services and Community Relations since October 2012. Previously served as Vice President of External Affairs from January 2005 until October 2012.

A. Nicole Faulk
Vice President
Age 42
Elected in 2015. Vice President of Customer Services Organization effective April 2015. Previously served as Region Vice President for the West Region of Georgia Power from March 2015 through April 2015, Region Manager for the Metro West Region of Georgia Power from December 2011 to March 2015, and a director of Nuclear Development at Southern Nuclear from March 2010 to December 2011.

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer
Age 51
Elected in 2010. Vice President, Treasurer, and Chief Financial Officer since August 2010.

R. Allen Reaves
Vice President
Age 56
Elected in 2010. Vice President and Senior Production Officer since August 2010.

Billy F. Thornton
Vice President
Age 55
Elected in 2012. Vice President of External Affairs since October 2012. Previously served as Director of External Affairs from October 2011 until October 2012, Director of Marketing from March 2011 through October 2011, and Major Account Sales Manager from June 2006 to March 2011.

Emile J. Troxclair, III
Vice President
Age 58
Elected in 2014. Vice President of Kemper Development since January 2015. Previously served as Vice President of Gasification for Lummus Technology Inc. from May 2013 through April 2014, Manager of E-Gas Technology for Phillips 66 from 2012 to May 2013, and Manager of E-Gas Technology for ConocoPhillips from 2003 to 2012.

The officers of Mississippi Power were elected at the meeting of the directors held on April 28, 2015 for a term of one year or until their successors are elected and have qualified, except for Mr. Wilson, whose election as President was effective October 19, 2015 and election as Chief Executive Officer was effective January 1, 2016.

PART II

Item 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(a)(1) The common stock of Southern Company is listed and traded on the NYSE. The common stock is also traded on regional exchanges across the U.S. The high and low stock prices as reported on the NYSE for each quarter of the past two years were as follows:

	High	Low
2015		
First Quarter	$ 53.16	$ 43.55
Second Quarter	45.44	41.40
Third Quarter	46.84	41.81
Fourth Quarter	47.50	43.38
2014		
First Quarter	$ 44.00	$ 40.27
Second Quarter	46.81	42.55
Third Quarter	45.47	41.87
Fourth Quarter	51.28	43.55

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

(a)(2) Number of Southern Company's common stockholders of record at January 31, 2016: 131,458

Each of the other registrants have one common stockholder, Southern Company.

(a)(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors. The dividends on common stock declared by Southern Company and the traditional operating companies to their stockholder(s) for the past two years were as follows:

Registrant	Quarter	2015	2014
		(in thousands)	
Southern Company	First	$ 478,454	$ 450,991
	Second	493,161	469,198
	Third	493,382	471,044
	Fourth	493,884	474,428
Alabama Power	First	142,820	137,390
	Second	142,820	137,390
	Third	142,820	137,390
	Fourth	142,820	137,390
Georgia Power	First	258,570	238,400
	Second	258,570	238,400
	Third	258,570	238,400
	Fourth	258,570	238,400
Gulf Power	First	32,540	30,800
	Second	32,540	30,800
	Third	32,540	30,800
	Fourth	32,540	30,800
Mississippi Power	First	—	54,930
	Second	—	54,930
	Third	—	54,930
	Fourth	—	54,930

In 2015 and 2014, Southern Power Company paid dividends to Southern Company as follows:

Registrant	Quarter	2015	2014
		(in thousands)	
Southern Power Company	First	$ 32,640	$ 32,780
	Second	32,640	32,780
	Third	32,640	32,780
	Fourth	32,640	32,780

The dividend paid per share of Southern Company's common stock was 52.50¢ for the first quarter 2015 and 54.25¢ each for the second, third, and fourth quarters of 2015. In 2014, Southern Company paid a dividend per share of 50.75¢ for the first quarter and 52.50¢ each for the second, third, and fourth quarters.

The traditional operating companies and Southern Power Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

(a)(4) Securities authorized for issuance under equity compensation plans.

See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

Item 6. SELECTED FINANCIAL DATA

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each of the registrants in Item 7 herein and Note 1 of each of the registrant's financial statements under "Financial Instruments" in Item 8 herein. See also Note 10 to the financial statements of Southern Company, Alabama Power, and Georgia

Power, Note 9 to the financial statements of Gulf Power and Mississippi Power, and Note 8 to the financial statements of Southern Power in Item 8 herein.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO 2015 FINANCIAL STATEMENTS

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls And Procedures.

As of the end of the period covered by this Annual Report on Form 10-K, Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

Internal Control Over Financial Reporting.

(a) Management's Annual Report on Internal Control Over Financial Reporting.

Southern Company's Management's Report on Internal Control Over Financial Reporting is included on page II-8 of this Form 10-K.

Alabama Power's Management's Report on Internal Control Over Financial Reporting is included on page II-131 of this Form 10-K.

Georgia Power's Management's Report on Internal Control Over Financial Reporting is included on page II-208 of this Form 10-K.

Gulf Power's Management's Report on Internal Control Over Financial Reporting is included on page II-292 of this Form 10-K.

Mississippi Power's Management's Report on Internal Control Over Financial Reporting is included on page II-362 of this Form 10-K.

Southern Power's Management's Report on Internal Control Over Financial Reporting is included on page II-450 of this Form 10-K.

(b) Attestation Report of the Registered Public Accounting Firm.

The report of Deloitte & Touche LLP, Southern Company's independent registered public accounting firm, regarding Southern Company's Internal Control over Financial Reporting is included on page II-9 of this Form 10-K. This report is not applicable to Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power as these companies are not accelerated filers or large accelerated filers.

(c) Changes in internal control over financial reporting.

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the fourth quarter 2015 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power Company's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None.

THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company and Subsidiary Companies 2015 Annual Report

The management of The Southern Company (Southern 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 Southern 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 Southern Company's internal control over financial reporting was effective as of December 31, 2015 .

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Southern Company's financial statements, has issued an attestation report on the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2015 . Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

/s/ Thomas A. Fanning
Thomas A. Fanning
Chairman, President, and Chief Executive Officer

/s/ Art P. Beattie
Art P. Beattie
Executive Vice President and Chief Financial Officer

February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
The Southern Company

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of The Southern Company and Subsidiary Companies (the Company) as of December 31, 2015 and 2014 , and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015 . We also have audited the Company's internal control over financial reporting as of December 31, 2015 , based on criteria established in *Internal Control* - *Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page II-8). Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements (pages II-52 to II-126) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2015 and 2014 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 , in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015 , based on the criteria established in *Internal Control* - *Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission .

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 26, 2016

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
2013 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2014 through 2016
AFUDC	Allowance for funds used during construction
AGL Resources	AGL Resources Inc.
Alabama Power	Alabama Power Company
APA	Asset purchase agreement
ASC	Accounting Standards Codification
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
Bridge Agreement	Senior unsecured Bridge Credit Agreement, dated as of September 30, 2015, among Southern Company, the lenders identified therein, and Citibank, N.A.
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
COD	Commercial operation date
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
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 by Mississippi Power in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Merger	The merger of Merger Sub with and into AGL Resources on the terms and subject to the conditions set forth in the Merger Agreement, with AGL Resources continuing as the surviving corporation and a wholly-owned, direct subsidiary of Southern Company
Merger Agreement	Agreement and Plan of Merger, dated as of August 23, 2015, among Southern Company, AGL Resources, and Merger Sub
Merger Sub	AMS Corp., a wholly-owned, direct subsidiary of Southern Company
Mirror CWIP	A regulatory liability account for use in mitigating future rate impacts for Mississippi Power customers
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MW	Megawatt
NCCR	Georgia Power's Nuclear Construction Cost Recovery

DEFINITIONS
(continued)

Term	Meaning
NDR	Alabama Power's Natural Disaster Reserve
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Georgia Power's Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company (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
Rate CNP	Alabama Power's Rate Certificated New Plant
Rate CNP Compliance	Alabama Power's Rate Certificated New Plant Compliance
Rate CNP Environmental	Alabama Power's Rate Certificated New Plant Environmental
Rate CNP PPA	Alabama Power's Rate Certificated New Plant Power Purchase Agreement
Rate ECR	Alabama Power's Rate Energy Cost Recovery
Rate NDR	Alabama Power's Rate Natural Disaster Reserve
Rate RSE	Alabama Power's Rate Stabilization and Equalization plan
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SMEPA	South Mississippi Electric Power Association
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Company and Subsidiary Companies 2015 Annual Report

OVERVIEW

Business Activities

The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the traditional operating companies and Southern Power Company and owns other direct and indirect subsidiaries. The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market.

Many factors affect the opportunities, challenges, and risks of the Southern Company system's electricity business. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, fuel, capital expenditures, including new plants, and restoration following major storms. Construction continues on Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in the two units, each with approximately 1,100 MWs) and Mississippi Power's 582 -MW Kemper IGCC. On December 3, 2015, the Mississippi PSC issued an order, based on a stipulation between Mississippi Power and the MPUS, authorizing Mississippi Power to implement rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service. Further proceedings related to cost recovery for the Kemper IGCC are expected after the remainder of the Kemper IGCC is placed in service which is currently expected in the third quarter 2016. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. In addition, on December 31, 2015, Georgia Power and the other parties to the commercial litigation related to the construction of Plant Vogtle Units 3 and 4 entered into a settlement agreement resulting in the dismissal of the litigation. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for more information.

Each of the traditional operating companies has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Southern Company system for the foreseeable future. See Note 3 to the financial statements under " Retail Regulatory Matters " and " Integrated Coal Gasification Combined Cycle " for additional information.

Another major factor is the profitability of the competitive market-based wholesale generating business. Southern Power's strategy is to acquire, construct, and sell power plants, including renewable energy projects, and to enter into PPAs primarily with investor-owned utilities, independent power producers, municipalities, and electric cooperatives.

Southern Company's other business activities include investments in leveraged lease projects and telecommunications. Management continues to evaluate the contribution of each of these activities to total shareholder return and may pursue acquisitions and dispositions accordingly.

Proposed Merger with AGL Resources

On August 23, 2015, Southern Company entered into the Merger Agreement to acquire AGL Resources. Under the terms of the Merger Agreement, subject to the satisfaction or waiver (if permissible under applicable law) of specified conditions, Merger Sub will be merged with and into AGL Resources. AGL Resources will survive the Merger and become a wholly-owned, direct subsidiary of Southern Company. Upon the consummation of the Merger, each share of common stock of AGL Resources issued and outstanding immediately prior to the effective time of the Merger (Effective Time), other than shares owned by AGL Resources as treasury stock, shares owned by a subsidiary of AGL Resources, and any shares owned by shareholders who have properly exercised and perfected dissenters' rights, will be converted into the right to receive $66 in cash, without interest and less any applicable withholding taxes (Merger Consideration). Other equity-based securities of AGL Resources will be cancelled for cash consideration or converted into new awards from Southern Company as described in the Merger Agreement.

Southern Company intends to initially fund the cash consideration for the Merger using a mix of debt and equity. Southern Company finances its capital needs on a portfolio basis and expects to issue approximately $8.0 billion in debt prior to closing the Merger and approximately $1.2 billion in equity during 2016. This capital is expected to provide funding for the Merger, Southern Power growth opportunities, and other Southern Company system capital projects. In addition, Southern Company entered into the $8.1 billion Bridge Agreement on September 30, 2015 to provide financing for the Merger in the event long-term financing is not available.

The Merger was approved by AGL Resources' shareholders on November 19, 2015, and the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 expired on December 4, 2015. Consummation of the Merger remains subject to the satisfaction or waiver of certain closing conditions, including, among others, (i) the approval of the California Public Utilities Commission, Georgia PSC, Illinois Commerce Commission, Maryland PSC, and New Jersey Board of Public Utilities, and other approvals required under applicable state laws, and the approval of the Federal Communications Commission (FCC) for the transfer of control over the FCC licenses of certain subsidiaries of AGL Resources, (ii) the absence of a judgment, order, decision, injunction, ruling, or other finding or agency requirement of a governmental entity prohibiting the consummation of the Merger, and (iii) other customary closing conditions, including (a) subject to certain materiality qualifiers, the accuracy of each party's representations and warranties and (b) each party's performance in all material respects of its obligations under the Merger Agreement. Southern Company completed the required state regulatory applications in the fourth quarter 2015 and the required FCC filings in February 2016. On February 24, 2016, a stipulation and settlement agreement between Southern Company, AGL Resources, the Maryland PSC Staff, and the Maryland Office of People's Counsel was filed with the Maryland PSC. The proposed settlement remains subject to the approval of the Maryland PSC. Additionally, Southern Company received the approval of the Virginia State Corporation Commission in February 2016.

Subject to certain limitations, either party may terminate the Merger Agreement if the Merger is not consummated by August 23, 2016, which date may be extended by either party to February 23, 2017 if, on August 23, 2016, all conditions to closing other than those relating to (i) regulatory approvals and (ii) the absence of legal restraints preventing consummation of the Merger (to the extent relating to regulatory approvals) have been satisfied. Upon termination of the Merger Agreement under certain specified circumstances, AGL Resources will be required to pay Southern Company a termination fee of $201 million or reimburse Southern Company’s expenses up to $5 million (which reimbursement shall reduce on a dollar-for-dollar basis any termination fee subsequently payable by AGL Resources). Southern Company currently expects to complete the transaction in the second half of 2016.

Prior to the Merger, Southern Company and AGL Resources will continue to operate as separate companies. Accordingly, except for specific references to the pending Merger, the descriptions of strategy and outlook and the risks and challenges Southern Company faces, and the discussion and analysis of results of operations and financial condition set forth herein relate solely to Southern Company. See Note 12 to the financial statements under "Southern Company – Proposed Merger with AGL Resources" and RISK FACTORS in Item 1A for additional information regarding the Merger and the various risks related thereto.

During 2015, the Company incurred external transaction costs for financing, legal, and consulting services associated with the proposed Merger of approximately $41 million.

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

Key Performance Indicators

In striving to achieve superior risk-adjusted returns while providing cost-effective energy to more than four million customers, the Southern Company system continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, execution of major construction projects, and earnings per share (EPS). Southern Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the results of the Southern Company system.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Southern Company system's fossil/hydro 2015 Peak Season EFOR was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Southern Company system's performance for 2015 was below the target for these transmission and distribution reliability measures primarily due to the level of storm activity in the service territory during the year. Primarily as a result of charges for estimated probable losses related to construction of the Kemper IGCC, Southern Company's EPS for 2015 did not meet the target on a GAAP basis. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Excluding t he charges for estimated probable losses related to construction of the Kemper IGCC, AGL Resources acquisition costs, and additional costs related to an insurance settlement, Southern Company's 2015 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2015 Target Performance	2015 Actual Performance
System Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season System EFOR — fossil/hydro	**6.02% or less**	**1.40%**
Basic EPS — As Reported	**$2.76-$2.88**	**$2.60**
Estimated Loss on Kemper IGCC [(a)]		**$0.25**
AGL Resources Acquisition Costs [(b)]		**$0.03**
Additional MC Asset Recovery Settlement Costs [(c)]		**$0.01**
EPS, excluding items*		**$2.89**

* The following three items are excluded from the EPS calculation:

(a) The estimated probable losses of $226 million after-tax, or $0.25 per share, related to Mississippi Power's construction of the Kemper IGCC. The estimated probable losses related to the construction of the Kemper IGCC significantly impacted the presentation of EPS in the table above, and any similar charges are items that may occur with uncertain frequency in the future. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

(b) The $31 million after-tax, or $0.03 per share, related to costs of the proposed Merger. Further costs related to the proposed Merger are expected to continue to occur in connection with closing the proposed Merger and supporting the related integration. See "Proposed Merger with AGL Resources" herein and Note 12 to the financial statements under "Southern Company – Proposed Merger with AGL Resources" for additional information.

(c) Additional insurance settlement costs of $4 million after-tax, or $0.01 per share, related to the March 2009 litigation settlement with MC Asset Recovery, LLC. Further costs related to the litigation settlement are not expected.

EPS, excluding items does not reflect EPS as calculated in accordance with GAAP. Southern Company management uses the non-GAAP measure of EPS, excluding these items, to evaluate the performance of Southern Company's ongoing business activities and its 2015 performance on a basis consistent with the assumptions used in developing the 2015 performance targets and to compare certain results to prior periods. Southern Company believes this presentation is useful to investors by providing additional information for purposes of evaluating the performance of Southern Company's business activities. This presentation is not meant to be considered a substitute for financial measures prepared in accordance with GAAP.

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

Earnings

Consolidated net income attributable to Southern Company was $2.4 billion in 2015, an increase of $404 million , or 20.6% , from the prior year. The increase was primarily related to lower pre-tax charges of $365 million ($226 million after tax) recorded in 2015 compared to pre-tax charges of $868 million ($536 million after tax) recorded in 2014 for revisions of the estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC and an increase in retail base rates. The increases were partially offset by increases in non-fuel operations and maintenance expenses and depreciation and amortization.

Consolidated net income attributable to Southern Company was $2.0 billion in 2014, an increase of $319 million , or 19.4% , from the prior year. The increase was primarily related to an increase in retail base rates, as well as colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. The increase in net income was also the result of lower pre-tax charges of $868 million ($536 million after tax) recorded in 2014 compared to pre-tax charges of $1.2 billion ($729 million after tax) recorded in 2013 for revisions of the estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC. These increases were partially offset by increases in non-fuel operations and maintenance expenses.

Basic EPS was $2.60 in 2015, $2.19 in 2014, and $1.88 in 2013. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.59 in 2015, $2.18 in 2014, and $1.87 in 2013. EPS for 2015 was negatively impacted by $0.04 per share as a result of an increase in the average shares outstanding. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein for additional information.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $2.1525 in 2015 , $2.0825 in 2014 , and $2.0125 in 2013 . In January 2016 , Southern Company declared a quarterly dividend of 54.25 cents per share. This is the 273rd consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2015 , the actual dividend payout ratio was 83% , while the payout ratio of net income excluding estimated probable losses relating to Mississippi Power's construction of the Kemper IGCC, AGL Resources acquisition costs, and additional costs related to an insurance settlement was 75%.

RESULTS OF OPERATIONS

Discussion of the results of operations is divided into two parts – the Southern Company system's primary business of electricity sales and its other business activities.

	Amount		
	2015	2014	2013
		(in millions)	
Electricity business	**$ 2,401**	$ 1,969	$ 1,652
Other business activities	**(34)**	(6)	(8)
Net Income	**$ 2,367**	$ 1,963	$ 1,644

Electricity Business

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers primarily in the Southeast.

A condensed statement of income for the electricity business follows:

	Amount	Increase (Decrease) from Prior Year	
	2015	**2015**	2014
		(in millions)	
Electric operating revenues	**$ 17,442**	**$ (964)**	$ 1,371
Fuel	**4,750**	**(1,255)**	495
Purchased power	**645**	**(27)**	211
Other operations and maintenance	**4,292**	**33**	481
Depreciation and amortization	**2,020**	**91**	43
Taxes other than income taxes	**995**	**16**	47
Estimated loss on Kemper IGCC	**365**	**(503)**	(312)
Total electric operating expenses	**13,067**	**(1,645)**	965
Operating income	**4,375**	**681**	406
Allowance for equity funds used during construction	**226**	**(19)**	55
Interest income	**22**	**4**	—
Interest expense, net of amounts capitalized	**774**	**(20)**	6
Other income (expense), net	**(54)**	**19**	(18)
Income taxes	**1,326**	**273**	118
Net income	**2,469**	**432**	319
Less:			
Dividends on preferred and preference stock of subsidiaries	**54**	**(14)**	2
Net income attributable to noncontrolling interests	**14**	**14**	—
Net Income Attributable to Southern Company	**$ 2,401**	**$ 432**	$ 317

Electric Operating Revenues

Electric operating revenues for 2015 were $17.4 billion , reflecting a $964 million decrease from 2014. Details of electric operating revenues were as follows:

	Amount	
	2015	2014
	(in millions)	
Retail — prior year	**$ 15,550**	$ 14,541
Estimated change resulting from —		
Rates and pricing	**375**	300
Sales growth	**50**	35
Weather	**(59)**	236
Fuel and other cost recovery	**(929)**	438
Retail — current year	**14,987**	15,550
Wholesale revenues	**1,798**	2,184
Other electric operating revenues	**657**	672
Electric operating revenues	**$ 17,442**	$ 18,406
Percent change	**(5.2)%**	8.0%

Retail revenues decreased $563 million , or 3.6% , in 2015 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2015 was primarily due to increased revenues at Alabama Power, associated with an increase in rates under Rate RSE, and at Georgia Power, related to base tariff increases approved by the Georgia PSC in accordance with the 2013 ARP, and increases in collections for financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, all effective January 1, 2015, as well as higher contributions from variable demand-driven pricing from commercial and industrial customers. The increase in rates and pricing was also due to the implementation of rates for the Kemper IGCC that began in August 2015 at Mississippi Power. The increase was partially offset by the correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing at Georgia Power.

Retail revenues increased $1.0 billion , or 6.9% , in 2014 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2014 was primarily due to increased revenues at Georgia Power related to base tariff increases effective January 1, 2014, as approved by the Georgia PSC in accordance with the 2013 ARP, and increases in collections for financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, as well as higher contributions from variable demand-driven pricing from commercial and industrial customers. Also contributing to the increase were increased revenues at Alabama Power associated with Rate CNP Environmental primarily resulting from the inclusion of pre-2005 environmental assets and increased revenues at Gulf Power primarily resulting from a retail base rate increase and an increase in the environmental cost recovery clause rate, both effective January 2014, as approved by the Florida PSC.

See Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Rate RSE," "–Rate CNP," " – Georgia Power – Rate Plans," " – Gulf Power – Retail Base Rate Case," and "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" and Note 1 to the financial statements under "General" for additional information. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. The traditional operating companies may also have one or more regulatory mechanisms to recover other costs such as environmental and other compliance costs, storm damage, new plants, and PPAs.

Wholesale revenues consist of PPAs primarily with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale revenues from PPAs (other than solar and wind PPAs) have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the

Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in 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. Wholesale revenues at Mississippi Power include FERC-regulated municipal and rural association sales as well as market-based sales. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

Wholesale revenues from power sales were as follows:

	2015	2014	2013
		(in millions)	
Capacity and other	**$ 875**	$ 974	$ 971
Energy	**923**	1,210	884
Total	**$ 1,798**	$ 2,184	$ 1,855

In 2015, wholesale revenues decreased $386 million , or 17.7% , as compared to the prior year due to a $287 million decrease in energy revenues and a $99 million decrease in capacity revenues. The decreases in energy revenues were primarily related to lower fuel costs and lower customer demand due to milder weather as compared to the prior year, partially offset by increases in energy revenues from new solar and wind PPAs at Southern Power. The decreases in capacity revenues were primarily due to the expiration of wholesale contracts in December 2014 at Georgia Power, unit retirements at Georgia Power, and PPA expirations at Southern Power. See FUTURE EARNINGS POTENTIAL – "Other Matters" for information regarding the expiration of long-term sales agreements at Gulf Power for Plant Scherer Unit 3, which will impact future wholesale earnings.

In 2014, wholesale revenues increased $329 million , or 17.7% , as compared to the prior year due to a $326 million increase in energy revenues and a $3 million increase in capacity revenues. The increase in energy revenues was primarily related to increased revenue under existing contracts as well as new solar PPAs and requirements contracts primarily at Southern Power, increased demand resulting from colder weather in the first quarter 2014 as compared to the corresponding period in 2013, and an increase in the average cost of natural gas. The increase in capacity revenues was primarily due to wholesale base rate increases at Mississippi Power, partially offset by a decrease in capacity revenues primarily due to lower customer demand and the expiration of certain requirements contracts at Southern Power.

Other Electric Revenues

Other electric revenues decreased $15 million , or 2.2% , and increased $33 million , or 5.2% , in 2015 and 2014, respectively, as compared to the prior years. The 2015 decrease was primarily due to a $16 million decrease in transmission revenues at Georgia Power primarily as a result of a contract that expired in December 2014 and a $13 million decrease in co-generation steam revenues at Alabama Power, partially offset by an $11 million increase in outdoor lighting revenues at Georgia Power. The 2014 increase was primarily due to increases in open access transmission tariff revenues and transmission service revenues primarily at Alabama Power and Georgia Power, an increase in co-generation steam revenues at Alabama Power, increases in outdoor lighting and solar application fee revenues at Georgia Power, as well as an increase in franchise fees at Gulf Power due to increased retail revenues.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2015 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2015	**2015**	2014	**2015***	2014
	(in billions)				
Residential	**52.1**	**(2.3)%**	5.5%	**0.4 %**	— %
Commercial	**53.5**	**0.5**	1.3	**0.9**	(0.4)
Industrial	**54.0**	**(0.4)**	3.3	**(0.3)**	3.3
Other	**0.9**	**(1.4)**	0.9	**(1.3)**	0.7
Total retail	**160.5**	**(0.7)**	3.3	**0.3 %**	0.9 %
Wholesale	**30.5**	**(7.0)**	21.7		
Total energy sales	**191.0**	**(1.8)%**	6.0%		

* In the first quarter 2015, Mississippi Power updated the methodology to estimate the unbilled revenue allocation among customer classes. This change did not have a significant impact on net income. The KWH sales variances in the above table reflect an adjustment to the estimated allocation of Mississippi Power's unbilled 2014 KWH sales among customer classes that is consistent with the actual allocation in 2015. Without this adjustment, 2015 weather-adjusted commercial sales increased 0.8% and industrial KWH sales decreased 0.4% 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 decreased 1.2 billion KWHs 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 and decreased customer usage, partially offset by customer growth. Weather-adjusted commercial KWH sales increased primarily due to customer growth and increased customer usage. Weather-adjusted residential KWH sales increased primarily due to customer growth, partially offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, had modest growth in 2015. The decrease in industrial KWH energy sales was primarily due to decreased sales in the primary metals, chemicals, and paper sectors, partially offset by increased sales in the transportation, stone, clay, and glass, pipeline, lumber, and petroleum sectors. A strong dollar, low oil prices, and weak global economic growth conditions constrained the industrial sector in 2015.

Retail energy sales increased 5.2 billion KWHs in 2014 as compared to the prior year. This increase was primarily the result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and customer growth, partially offset by a decrease in customer usage. The increase in industrial KWH energy sales was primarily due to increased sales in the primary metals, chemicals, paper, non-manufacturing, transportation, and stone, clay, and glass sectors. Weather-adjusted commercial KWH energy sales decreased primarily due to decreased customer usage, partially offset by customer growth. Weather-adjusted residential KWH energy sales were flat compared to the prior year as a result of customer growth offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

See "Electric Operating Revenues" above for a discussion of significant changes in wholesale revenues related to changes in price and KWH sales.

Fuel and Purchased Power Expenses

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

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

	2015	2014	2013
Total generation *(billions of KWHs)*	**187**	191	179
Total purchased power *(billions of KWHs)*	**13**	12	12
Sources of generation *(percent)* —			
Coal	**34**	42	39
Nuclear	**16**	16	17
Gas	**46**	39	40
Hydro	**3**	3	4
Other Renewables	**1**	—	—
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**3.55**	3.81	4.01
Nuclear	**0.79**	0.87	0.87
Gas	**2.60**	3.63	3.29
Average cost of fuel, generated *(cents per net KWH)*	**2.64**	3.25	3.17
Average cost of purchased power *(cents per net KWH)**	**6.11**	7.13	5.27

* Average cost of purchased power includes fuel purchased by the Southern Company system for tolling agreements where power is generated by the provider.

In 2015, total fuel and purchased power expenses were $5.4 billion , a decrease of $1.3 billion , or 19.2% , as compared to the prior year. The decrease was primarily the result of a $1.1 billion decrease in the average cost of fuel and purchased power primarily due to lower coal and natural gas prices and a $137 million net decrease in the volume of KWHs generated and purchased due to milder weather in the first and fourth quarters of 2015.

In 2014, total fuel and purchased power expenses were $6.7 billion , an increase of $706 million , or 11.8% , as compared to the prior year. The increase was primarily the result of a $422 million increase in the volume of KWHs generated primarily due to increased demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and a $286 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices.

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

Fuel

In 2015, fuel expense was $4.8 billion , a decrease of $1.3 billion , or 20.9% , as compared to the prior year. The decrease was primarily due to a 28.4% decrease in the average cost of natural gas per KWH generated, a 19.2% decrease in the volume of KWHs generated by coal, and a 6.8% decrease in the average cost of coal per KWH generated, partially offset by a 15.9% increase in the volume of KWHs generated by natural gas.

In 2014, fuel expense was $6.0 billion , an increase of $495 million , or 9.0% , as compared to the prior year. The increase was primarily due to a 12.7% increase in the volume of KWHs generated by coal, a 10.3% increase in the average cost of natural gas per KWH generated, and a 30.7% decrease in the volume of KWHs generated by hydro facilities resulting from less rainfall, partially offset by a 5.0% decrease in the average cost of coal per KWH generated.

Purchased Power

In 2015, purchased power expense was $645 million , a decrease of $27 million , or 4.0% , as compared to the prior year. The decrease was primarily due to a 14.3% decrease in the average cost per KWH purchased primarily as a result of lower natural gas prices, partially offset by a 5.3% increase in the volume of KWHs purchased.

In 2014, purchased power expense was $672 million , an increase of $211 million , or 45.8% , as compared to the prior year. The increase was primarily due to a 35.3% increase in the average cost per KWH purchased.

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

Other Operations and Maintenance Expenses

Other operations and maintenance expenses increased $33 million , or 0.8% , in 2015 as compared to the prior year. The increase was primarily related to an $84 million increase in employee compensation and benefits including pension costs, a $62 million increase in generation expenses primarily related to environmental costs, and an $11 million increase in customer accounts, service, and sales costs primarily related to customer incentive and demand-side management programs, partially offset by a $99 million decrease in transmission and distribution costs primarily related to reduced overhead line maintenance and gains from sales of transmission assets and a $32 million decrease in scheduled outage and maintenance costs at generation facilities.

Other operations and maintenance expenses increased $481 million , or 12.7% , in 2014 as compared to the prior year. The increase was primarily related to increases of $149 million in scheduled outage costs at generation facilities, $103 million in other generation expenses primarily related to commodity and labor costs, $103 million in transmission and distribution costs primarily related to overhead line maintenance, $42 million in net employee compensation and benefits including pension costs, and $31 million in customer accounts, service, and sales costs primarily related to customer incentive and demand-side management programs.

Production expenses and transmission and distribution expenses fluctuate from year to year due to variations in outage and maintenance schedules and normal changes in the cost of labor and materials.

Depreciation and Amortization

Depreciation and amortization increased $91 million , or 4.7% , in 2015 as compared to the prior year primarily due to the amortization of $120 million of the regulatory liability for other cost of removal obligations in 2014 at Alabama Power and increases in additional plant in service at the traditional operating companies and Southern Power, partially offset by a decrease as a result of a reduction in depreciation rates at Alabama Power effective January 1, 2015, a decrease due to unit retirements at Georgia Power, and a reduction in depreciation at Gulf Power as authorized in the 2013 rate case settlement agreement approved by the Florida PSC. See Note 3 to the financial statements under "Retail Regulatory Matters – Gulf Power – Retail Base Rate Case" for additional information.

Depreciation and amortization increased $43 million , or 2.3% , in 2014 as compared to the prior year primarily due to increases in depreciation rates related to environmental assets and the amortization of certain regulatory assets at Alabama Power and the completion of the amortization of certain regulatory liabilities at Georgia Power. Also contributing to the increase were increases at Southern Power in plant in service related to the addition of solar facilities in 2013 and 2014, an increase related to equipment retirements resulting from accelerated outage work, and additional component depreciation as a result of increased production. These increases were largely offset by the amortization of $120 million of the regulatory liability for other cost of removal obligations at Alabama Power.

See Note 1 to the financial statements under "Regulatory Assets and Liabilities" and "Depreciation and Amortization" and Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Rate CNP" and "– Cost of Removal Accounting Order" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $16 million , or 1.6% , in 2015 as compared to the prior year primarily due to an increase in ad valorem and property taxes.

Taxes other than income taxes increased $47 million , or 5.0% , in 2014 as compared to the prior year primarily due to increases of $34 million in municipal franchise fees related to higher retail revenues in 2014 and $16 million in payroll taxes primarily related to higher employee benefits.

Estimated Loss on Kemper IGCC

In 2015 and 2014, estimated probable losses on the Kemper IGCC of $365 million and $868 million , respectively, were recorded at Southern Company. These losses reflect revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power 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). 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 decreased $19 million , or 7.8% , in 2015 as compared to the prior year primarily due to a reduction in the AFUDC rate at Mississippi Power, as well as placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014, partially offset by an increase in construction projects related to environmental and steam generation at Alabama Power.

AFUDC equity increased $55 million , or 28.9% , in 2014 as compared to the prior year primarily due to additional capital expenditures at the traditional operating companies, primarily related to environmental and transmission projects, as well as Mississippi Power placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014.

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

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $20 million , or 2.5% , in 2015 as compared to the prior year primarily due to a decrease of $58 million at Mississippi Power related to the termination of an agreement for SMEPA to purchase a portion of the Kemper IGCC which required the return of SMEPA's deposits at a lower rate of interest than accrued and a $14 million decrease primarily due to an increase in capitalized interest associated with the construction of solar facilities at Southern Power, partially offset by a $46 million increase due to higher average outstanding long-term debt balances at the traditional operating companies.

Interest expense, net of amounts capitalized increased $6 million , or 0.8% , in 2014 as compared to the prior year primarily due to a higher amount of outstanding long-term debt and an increase in interest expense resulting from the deposits received by Mississippi Power in January and October 2014 from SMEPA, partially offset by a decrease in interest expense related to the refinancing of long-term debt at lower rates and an increase in capitalized interest.

See Note 6 to the financial statements for additional information.

Other Income (Expense), Net

Other income (expense), net increased $19 million , or 26.0% , in 2015 as compared to the prior year primarily due to an increase of $9 million in wholesale operating fee revenues, an increase of $9 million in customer contributions in aid of construction at Georgia Power, and an increase due to Mississippi Power's $7 million settlement with the Sierra Club in 2014, partially offset by a decrease in sales of non-utility property at Alabama Power **.**

Other income (expense), net decreased $18 million , or 32.7% , in 2014 as compared to the prior year primarily due to an $8 million decrease in wholesale operating fee revenues at Georgia Power and $7 million associated with Mississippi Power's settlement with the Sierra Club.

Income Taxes

Income taxes increased $273 million , or 25.9% , in 2015 as compared to the prior year primarily due to a reduction in tax benefits related to the estimated probable losses on Mississippi Power's construction of the Kemper IGCC recorded in 2014 and higher pre-tax earnings, partially offset by increased federal income tax benefits related to ITCs at Southern Power in 2015.

Income taxes increased $118 million , or 12.6% , in 2014 as compared to the prior year primarily due to higher pre-tax earnings, partially offset by an increase in non-taxable AFUDC equity and an increase in federal income tax benefits related to ITCs on Southern Power solar projects placed in service in 2014.

Other Business Activities

Southern Company's other business activities include the parent company (which does not allocate operating expenses to business units), investments in leveraged lease projects, and telecommunications. These businesses are classified in general categories and may comprise one or both of the following subsidiaries: Southern Company Holdings, Inc. (Southern Holdings) invests in various projects, including leveraged lease projects, and SouthernLINC Wireless provides digital wireless communications for use by

Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast.

On February 24, 2016, Southern Company entered into an Agreement and Plan of Merger to acquire PowerSecure International, Inc. Under the terms of this merger agreement, the stockholders of PowerSecure International, Inc. will be entitled to receive $18.75 in cash for each share of common stock in a transaction with a total purchase price of approximately $431 million. Following this transaction, PowerSecure International, Inc. will become a wholly-owned subsidiary of Southern Company. This transaction is expected to close by the end of the second quarter 2016, subject to, among other items, approval by PowerSecure International, Inc. stockholders and notification, clearance, and reporting requirements under the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

A condensed statement of income for Southern Company's other business activities follows:

	Amount	Increase (Decrease) from Prior Year	
	2015	**2015**	2014
		(in millions)	
Operating revenues	**$ 47**	**$ (14)**	$ 9
Other operations and maintenance	**124**	**29**	27
Depreciation and amortization	**14**	**(2)**	1
Taxes other than income taxes	**2**	**—**	—
Total operating expenses	**140**	**27**	28
Operating income (loss)	**(93)**	**(41)**	(19)
Interest income	**1**	**—**	—
Other income (expense), net	**(8)**	**(18)**	36
Interest expense	**66**	**25**	5
Income taxes	**(132)**	**(56)**	10
Net income (loss)	**$ (34)**	**$ (28)**	$ 2

Operating Revenues

Southern Company's non-electric operating revenues for these other business activities decreased $14 million , or 23.0% , in 2015 as compared to the prior year. The decrease was primarily related to lower operating revenues at Southern Holdings due to higher billings in 2014 related to work performed on a generating plant outage and decreases in revenues at SouthernLINC Wireless related to lower average per subscriber revenue and fewer subscribers due to continued competition in the industry. Non-electric operating revenues for these other businesses increased $9 million , or 17.3% , in 2014 as compared to the prior year. The increase was primarily related to higher operating revenues at Southern Holdings due to higher billings related to work performed on a generating plant outage, partially offset by decreases in revenues at SouthernLINC Wireless related to lower average per subscriber revenue and fewer subscribers due to continued competition in the industry.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other business activities increased $29 million , or 30.5% , in 2015 as compared to the prior year. The increase was primarily due to parent company expenses of $27 million related to the proposed Merger, partially offset by lower operating expenses at Southern Holdings due to work performed on a generating plant outage in 2014. Other operations and maintenance expenses for these other business activities increased $27 million , or 39.7% , in 2014 as compared to the prior year. The increase was primarily related to insurance proceeds received in 2013 related to a litigation settlement with MC Asset Recovery, LLC and higher operating expenses at Southern Holdings due to work performed on a generating plant outage.

Other Income (Expense), Net

Other income (expense), net for these other business activities decreased $18 million in 2015 as compared to the prior year. The decrease was primarily due to parent company expenses of $14 million related to the proposed Merger. Other income (expense), net for these other business activities increased $36 million in 2014 as compared to the prior year. The increase was primarily due to the restructuring of a leveraged lease investment in the first quarter of 2013 and a decrease in charitable contributions in 2014.

Southern Company has several leveraged lease agreements which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. See Note 1 to the financial statements under "Leveraged Leases" for additional information.

Interest Expense

Interest expense for these other business activities increased $25 million , or 61.0% , in 2015 as compared to the prior year primarily due to an increase in outstanding long-term debt. Interest expense for these other business activities increased $5 million , or 13.9% , in 2014 as compared to 2013 primarily due to an increase in outstanding long-term debt, partially offset by the refinancing of long-term debt at lower rates.

Income Taxes

Income taxes for these other business activities decreased $56 million , or 73.7% , in 2015 as compared to the prior year primarily as a result of state income tax benefits realized in 2015 and changes in pre-tax earnings (losses). Income taxes for these other business activities increased $10 million , or 11.6% , in 2014 as compared to the prior year primarily as a result of changes in pre-tax earnings (losses).

Effects of Inflation

The traditional operating companies are subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Southern Power is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on Southern Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The four traditional operating companies operate as vertically integrated utilities providing electricity to customers within their service areas in the Southeast. Prices for electricity provided to retail customers are set by state PSCs under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Southern Power continues to focus on long-term capacity contracts. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Southern Company system's primary business of selling electricity. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment that allows for the timely recovery of prudently-incurred costs during a time of increasing costs and the completion and subsequent operation of the Kemper IGCC and Plant Vogtle Units 3 and 4 as well as other ongoing construction projects. Other major factors include the profitability of the competitive wholesale business and successfully expanding investments in renewable and other energy projects. Future earnings for the electricity business in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts 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 service territory. In addition, the level of future earnings for the wholesale business also depends on numerous factors including regulatory matters, creditworthiness of customers, total generating capacity available and related costs, future acquisitions and construction of generating facilities, including the impact of ITCs, and the successful remarketing of capacity as current contracts expire. Demand for electricity is partially 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.

As part of its ongoing effort to adapt to changing market conditions, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, and acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company. In addition, the proposed Merger will result in a combined company that is subject to various risks that do not currently impact Southern Company.

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 market-based contracts. 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 electric utilities' operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; 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 2015 , the traditional operating companies had invested approximately $11.4 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $0.9 billion, $1.1 billion, and $0.7 billion for 2015 , 2014 , and 2013 , respectively. The Southern Company system expects that capital expenditures to comply with environmental statutes and regulations will total approximately $1.8 billion from 2016 through 2018 , with annual totals of approximately $0.7 billion , $0.5 billion , and $0.6 billion for 2016 , 2017 , and 2018 , respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Southern Company system also anticipates costs associated with closure in place or by other methods, and ground water monitoring of ash ponds in accordance with the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation (ARO) liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

The Southern Company system'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 outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the fuel mix of the electric utilities. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, 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 – Alabama Power – Environmental Accounting Order" and "Retail Regulatory Matters – Georgia Power – Integrated Resource Plan" herein for additional information on planned unit retirements and fuel conversions at Alabama Power and Georgia Power, respectively.

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 electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Southern Company system. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. The compliance deadline set by the final MATS rule was April 16, 2015, with provisions for extensions to April 16, 2016. The implementation strategy for the MATS rule includes emission controls, retirements, and fuel conversions to achieve compliance by the deadlines applicable to each unit within the Southern Company system. On June 29, 2015, the U.S. Supreme Court issued a decision finding that in developing the MATS rule the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units. On December 15, 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule to the EPA without vacatur to respond to the U.S. Supreme Court's decision. The EPA's supplemental finding in response to the U.S. Supreme Court's decision, which the EPA proposes to finalize in April 2016, is not expected to have any impact on the MATS rule compliance requirements and deadlines.

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. The only area within the traditional operating companies' service territory designated as an ozone nonattainment area for the 2008 standard is a 15-county area within metropolitan Atlanta. On October 26, 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 will recommend area designations by October 2016, and the EPA is expected to finalize them by October 2017.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the traditional operating companies' service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS and the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard in December 2014, and no new nonattainment areas were designated within the traditional operating companies' service territory. The EPA has, however, deferred designation decisions for certain areas in Florida and Georgia.

Final revisions to the NAAQS for sulfur dioxide (SO_2), which established a new one-hour standard, became effective in 2010. No areas within the Southern Company system's service territory have been designated as nonattainment under this rule. However, the EPA has finalized a data requirements rule to support additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Southern Company system's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

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

Each of the states in which the Southern Company system has fossil generation is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I having begun in 2015 and Phase II beginning in 2017. On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Alabama, Florida, Georgia, North Carolina, and Texas, but rejected all other pending challenges to the rule. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. On December 3, 2015, the EPA published a proposed revision to CSAPR that would revise existing ozone-season emissions budgets for nitrogen oxide in Alabama and Mississippi and would remove Florida from the CSAPR program. The EPA proposes to finalize this rulemaking by summer 2016.

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.

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

On June 12, 2015, the EPA published a final rule requiring certain states (including Alabama, Florida, Georgia, Mississippi, North Carolina, and Texas) 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) by no later than November 22, 2016.

The Southern Company system has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. As part of this strategy, certain of the traditional operating companies have developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, the Alabama opacity rule, CSAPR, regional haze regulations, the MATS rule, the NSPS for CTs, and the SSM rule on the Southern Company system cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. 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.

In addition to the federal air quality laws described above, Georgia Power has also been subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule and a companion rule required reductions in emissions of mercury, SO_2, and nitrogen oxide state-wide through the installation of specified control technologies and a 95% reduction in SO_2 emissions at certain coal-fired generating units by specific dates between 2008 and 2015. In 2015, Georgia Power completed implementation of the measures necessary to comply with the Georgia Multi-Pollutant Rule at all 16 of its coal-fired generating units required to be controlled under the rule.

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 October 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

On November 3, 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 National Pollutant Discharge Elimination System 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. The ultimate impact of these requirements will depend on pending and any future legal challenges, compliance dates, and implementation of the final rule and cannot be determined at this time.

On June 29, 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 August 28, 2015, but on October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The ultimate impact of the final rule will depend on the outcome of this and other pending legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs.

Coal Combustion Residuals

The traditional operating companies currently manage CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at 22 electric generating plants. In addition to on-site storage, the traditional operating companies also sell a portion of their CCR to third parties for beneficial reuse. Individual states regulate CCR and the states in the Southern Company system's service territory each have their own regulatory requirements. Each traditional operating company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On April 17, 2015, the EPA published the CCR Rule in the Federal Register, which became effective on October 19, 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. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

Based on initial cost estimates for closure in place or by other methods, and groundwater monitoring of ash ponds pursuant to the CCR Rule, Southern Company recorded incremental 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, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the traditional operating companies expect to continue to periodically update these estimates. The traditional operating companies are currently completing an analysis of the plan of closure for all ash ponds in the Southern Company system, including the timing of closure and related cost recovery through regulated rates subject to the traditional operating companies' respective state PSC approval. Based on the results of that analysis, the traditional operating companies may accelerate the timing of some ash pond closures which could increase their ARO liabilities from the amounts presently recorded. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the traditional operating companies' ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. Southern 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 Southern Company's AROs as of December 31, 2015.

Environmental Remediation

The Southern Company system 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 Southern Company system could incur substantial costs to clean up affected sites. The traditional operating companies conduct studies to determine the extent of any required cleanup and the Company has recognized in its financial statements the costs to clean up known impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs. The traditional operating companies may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

On October 23, 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 its review with the courts. The stay will remain in effect through the resolution of the litigation, whether resolved in the U.S. Court of Appeals for the District of Columbia Circuit or 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. Southern 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 Southern Company system cannot be determined at this time and will depend upon numerous factors, including the Southern Company system's ongoing review of the final rules; the outcome of legal challenges, including legal challenges filed by the traditional operating companies; individual state implementation of the EPA's final guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

The United Nations 21 st international climate change conference took place in late 2015. The result was the adoption of 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 increasing those commitments every five years. The ultimate impact of this agreement depends on its ratification and implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Southern Company system's 2014 greenhouse gas emissions were approximately 112 million metric tons of CO_2 equivalent. The preliminary estimate of the Southern Company system's 2015 greenhouse gas emissions on the same basis is approximately 101 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

The traditional operating companies and Southern Power have 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 operating companies and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. The FERC directed the traditional operating companies 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 operating companies and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Alabama Power

Alabama Power 's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Alabama PSC. Alabama Power currently recovers its costs from the regulated retail business primarily through Rate RSE, Rate CNP, Rate ECR, and Rate NDR. In addition, the Alabama PSC issues accounting orders to address current events impacting Alabama Power. See Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power" for additional information regarding Alabama Power's rate mechanisms and accounting orders.

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon Alabama Power's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If Alabama Power's actual retail return is above the allowed WCE range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

On November 30, 2015, Alabama Power made its annual Rate RSE submission to the Alabama PSC of projected data for 2016. Projected earnings were within the specified WCE range; therefore, retail rates under Rate RSE remained unchanged for 2016.

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. Alabama Power may also recover retail costs associated with certificated PPAs under

Rate CNP PPA. On March 3, 2015, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2015 through March 31, 2016. No adjustment to Rate CNP PPA is expected in 2016.

Rate CNP Environmental allowed for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, and other such mandates. On March 3, 2015, the Alabama PSC approved a modification to Rate CNP Environmental to include compliance costs for both environmental and non-environmental mandates. The recoverable non-environmental compliance costs result from laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. This modification to Rate CNP Environmental was effective March 20, 2015 with the revised rate now defined as Rate CNP Compliance. Alabama Power was limited to recover $50 million of non-environmental compliance costs for the year 2015. Additional non-environmental compliance costs were recovered through Rate RSE. Customer rates were not impacted by this order in 2015; therefore, the modification increased the under recovered position for Rate CNP Compliance during 2015. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital.

On November 30, 2015, Alabama Power made its annual Rate CNP Compliance submission to the Alabama PSC of its cost of complying with governmental mandates for cost year 2016. Rate CNP Compliance increased 4.5%, or approximately $250 million annually, effective January 1, 2016.

Environmental Accounting Order

Based on an order from the Alabama PSC, Alabama Power is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. These costs are being amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance. See "Environmental Matters – Environmental Statutes and Regulations" herein for additional information regarding environmental regulations.

In April 2015, as part of its environmental compliance strategy, Alabama Power retired Plant Gorgas Units 6 and 7 (200 MWs). Additionally, in April 2015, Alabama Power ceased using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. In accordance with the joint stipulation entered in connection with a civil enforcement action by the EPA, Alabama Power retired Plant Barry Unit 3 (225 MWs) in August 2015 and it is no longer available for generation. Alabama Power expects to cease using coal at Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas by April 2016.

In accordance with this accounting order from the Alabama PSC, Alabama Power transferred the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized and recovered through Rate CNP Compliance over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on Southern Company's financial statements.

Cost of Removal Accounting Order

In accordance with an accounting order issued in November 2014 by the Alabama PSC, in December 2014, Alabama Power fully amortized the balance of $123 million in certain regulatory asset accounts and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset accounts fully amortized and terminated as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, which were approved by the Alabama PSC in 2012 and 2013, respectively. Approximately $95 million of non-nuclear outage costs and $28 million of compliance and pension costs previously deferred were fully amortized in December 2014.

Georgia Power

Georgia Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. Georgia Power currently recovers its costs from the regulated retail business through the 2013 ARP, which includes traditional base tariff rates, Demand-Side Management (DSM) tariffs, Environmental Compliance Cost Recovery (ECCR) tariffs, and Municipal Franchise Fee (MFF) tariffs. In addition, financing costs related to the construction of Plant Vogtle Units 3 and 4 are being collected through the NCCR tariff and fuel costs are collected through separate fuel cost recovery tariffs. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power" for additional information.

Rate Plans

In 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among Georgia Power, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors.

On December 16, 2015, in accordance with the 2013 ARP, the Georgia PSC approved an increase to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million ; (2) ECCR tariff by approximately $75 million ; (3) DSM tariffs by approximately $3 million ; and (4) MFF tariff by approximately $13 million , for a total increase in base revenues of approximately $140 million .

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, Georgia Power's retail ROE exceeded 12.00% , and Georgia Power will refund to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, Georgia Power's retail ROE was within the allowed retail ROE range.

Georgia Power is required to file a general base rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plan

See "Environmental Matters" and "Rate Plans" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent limitations guidelines for steam electric power plants, and additional regulations of CCR and CO_2 ; the State of Georgia's Multi-Pollutant Rule; and Georgia Power's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations.

To comply with the April 16, 2015 effective date of the MATS rule, Plant Branch Units 1, 3, and 4 (1,266 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) were retired and operations were discontinued at Plant Mitchell Unit 3 (155 MWs) by April 15, 2015, and Plant Kraft Units 1 through 4 (316 MWs) were retired on October 13, 2015. The switch to natural gas as the primary fuel was completed at Plant Yates Units 6 and 7 by June 2015 and at Plant Gaston Units 1 through 4 by December 2015.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years ending December 2022 and the amortization of the remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024.

On January 29, 2016, Georgia Power filed its triennial IRP (2016 IRP). The filing included a request to decertify Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs) upon approval of the 2016 IRP. The 2016 IRP also reflects that Georgia Power exercised its contractual option to sell its 33% ownership interest in the Intercession City unit (143 MWs total capacity) to Duke Energy Florida, Inc. See Note 4 to the financial statements for additional information.

In the 2016 IRP, Georgia Power requested reclassification of the remaining net book value of Plant Mitchell Unit 3, as of its retirement date, to a regulatory asset to be amortized over a period equal to the unit's remaining useful life. Georgia Power also requested that the Georgia PSC approve the deferral of the cost associated with materials and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a period deemed appropriate by the Georgia PSC.

The decertification and retirement of these units are not expected to have a material impact on Southern Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's orders in the 2016 IRP and next general base rate case.

Additionally, the 2016 IRP included a Renewable Energy Development Initiative requesting to procure up to 525 MWs of renewable resources utilizing market-based prices established through a competitive bidding process to expand Georgia Power's existing renewable initiatives, including the Advanced Solar Initiative (ASI).

A decision from the Georgia PSC on the 2016 IRP is expected in the third quarter 2016. The ultimate outcome of these matters cannot be determined at this time.

Renewables

On September 16, 2015, the Alabama PSC approved Alabama Power's petition for a Renewable Generation Certificate for up to 500 MWs. This will allow Alabama Power to build its own renewable projects, each less than 80 MWs, or purchase power from other renewable-generated sources.

In May 2014, the Georgia PSC approved Georgia Power's application for the certification of two PPAs executed in 2013 for the purchase of energy from two wind farms in Oklahoma with capacity totaling 250 MWs that will begin in 2016 and end in 2035.

As part of the Georgia Power ASI, Georgia Power executed ten PPAs that were approved by the Georgia PSC in 2014 and provide for the purchase of energy from 515 MWs of solar capacity. Two PPAs began in December 2015 and eight are expected to begin in December 2016, all of which have terms ranging from 20 to 30 years. As a result of certain acquisitions by Southern Power, Georgia Power expects that 249 MWs of the 515 MWs of contracted capacity will be purchased from solar facilities owned or under development by Southern Power.

In October 2014, the Georgia PSC approved Georgia Power's request to build, own, and operate three 30-MW solar generation facilities at three U.S. Army bases by the end of 2016. One of the three solar generation facilities began commercial operation on December 31, 2015. In addition, in December 2014, the Georgia PSC approved Georgia Power's request to build, own, and operate a 30-MW solar generation facility at Kings Bay Naval facility. On July 21, 2015, the Georgia PSC approved Georgia Power's request to build and operate an up to 46-MW solar generation facility at a U.S. Marine Corps base in Albany, Georgia. Georgia Power subsequently determined that a 31-MW facility will be constructed on the site. On December 22, 2015, the Georgia PSC approved Georgia Power's request to build and operate the remaining 15 MWs at a separate facility on the Fort Stewart Army base in Hinesville, Georgia. These facilities are expected to be operational by the end of 2016.

On April 7, 2015, the Georgia PSC approved the consolidation of four PPAs each with the same counterparty into two new PPAs with new biomass facilities. Under the terms of the order, the total 116 MWs from the existing four PPAs provided the capacity for two new PPAs of 58 MWs each. The new PPAs were executed on June 15, 2015 and November 23, 2015 and will begin in June 2017. See "Retail Regulatory Matters – Georgia Power – Integrated Resource Plan" herein for additional information on Georgia Power's renewables activities.

On April 16, 2015, the Florida PSC approved three energy purchase agreements totaling 120 MWs of utility-scale solar generation located at three military installations in northwest Florida. Purchases under these solar agreements are expected to begin by early 2017. On May 5, 2015, the Florida PSC approved an energy purchase agreement for up to 178 MWs of wind generation in central Oklahoma. Purchases under these agreements began in January 2016, are for energy only, and will be recovered through Gulf Power's fuel cost recovery mechanism.

On November 10, 2015, the Mississippi PSC issued three separate orders approving three solar facilities for a combined total of approximately 105 MWs. Mississippi Power will purchase all of the energy produced by the solar facilities for the 25-year term of the contracts under three PPAs, two of which have been finalized and one of which remains under negotiation. The projects are expected to be in service by the end of 2016 and the resulting energy purchases will be recovered through Mississippi Power's fuel cost recovery mechanism.

See Note 12 to the financial statements for information on Southern Power's renewables activities.

Retail Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow. The traditional operating companies continuously monitor their under or over recovered fuel cost balances and make appropriate filings with their state PSCs to adjust fuel cost recovery rates as necessary. During 2015, each of the traditional operating companies filed requests with their respective state PSCs for fuel rate decreases. Upon approval of these requests, each of the traditional operating companies decreased fuel rates in January 2016.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Rate ECR" and "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" for additional information.

Construction Program

Overview

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new generating facilities, as well as adding or changing fuel sources for certain existing units, adding environmental control equipment, and expanding the transmission and distribution systems. For the traditional operating companies, major generation construction projects are subject to state PSC approval in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. The construction programs of the traditional operating companies and Southern Power are currently estimated to include an investment of approximately $7.3 billion , $5.2 billion , and $5.5 billion for 2016 , 2017 , and 2018 , respectively.

The two largest construction projects currently underway in the Southern Company system are Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in the two units, each with approximately 1,100 MWs) and Mississippi Power's Kemper IGCC. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information. For additional information about costs relating to Southern Power's acquisitions that involve construction of renewable energy facilities, see Note 12 to the financial statements under "Southern Power – Construction Projects."

Also see FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information regarding Southern Company's capital requirements for its subsidiaries' construction programs.

Integrated Coal Gasification Combined Cycle

Mississippi Power's current cost estimate for the Kemper IGCC in total is approximately $6.63 billion, which includes approximately $5.29 billion of costs subject to the construction cost cap. Mississippi Power does not intend to seek any rate recovery for any related costs that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. In the aggregate, the Company has incurred charges of $2.41 billion ($1.5 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2015. Mississippi Power's current cost estimate includes costs through August 31, 2016. In subsequent periods, any further changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of income and these changes could be material.

During 2015, events related to the Kemper IGCC had a significant adverse impact on Mississippi Power's financial condition. These events include (i) the termination by SMEPA in May 2015 of the APA between Mississippi Power and SMEPA, whereby SMEPA previously agreed to purchase a 15% undivided interest in the Kemper IGCC, and Mississippi Power's subsequent return of approximately $301 million, including interest, to SMEPA; (ii) the termination of Mirror CWIP rates in July 2015 and the refund of $371 million in Mirror CWIP rate collections, including carrying costs, in the fourth quarter 2015 as a result of the Mississippi Supreme Court's reversal of the Mississippi PSC's 2013 rate order authorizing the collection of $156 million annually in Mirror CWIP rates; and (iii) the required recapture in December 2015 of $235 million of Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 48A (Phase II) tax credits as a result of the extension of the expected in-service date for the Kemper IGCC.

As a result of the termination of the Mirror CWIP rates, Mississippi Power submitted a filing to the Mississippi PSC requesting interim rates to collect approximately $159 million annually until a final rate decision could be made on Mississippi Power's request to recover costs associated with Kemper IGCC assets that had been placed in service. The Mississippi PSC approved the implementation of the requested interim rates in August 2015. Subsequently, on December 3, 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), based on a stipulation between Mississippi Power and the MPUS, authorizing Mississippi Power to replace the interim rates with rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service. Further proceedings related to cost recovery for the Kemper IGCC are expected after the remainder of the Kemper IGCC is placed in service, which is currently expected in the third quarter 2016. On February 25, 2016, Greenleaf CO2 Solutions, LLC filed a notice of appeal of the In-Service Asset Rate Order with the Mississippi Supreme Court. Mississippi Power believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on Southern Company's results of operations.

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

Nuclear Construction

On December 31, 2015, Westinghouse Electric Company LLC (Westinghouse) and Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and Westinghouse and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (Westinghouse and Stone & Webster, Inc., collectively, Contractor) under the engineering, procurement, and construction agreement between the Vogtle Owners and the Contractor (Vogtle 3 and 4 Agreement), including the pending litigation between the Vogtle Owners and the Contractor (Vogtle Construction Litigation).

Effective December 31, 2015, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to match the current estimated in-service dates of June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will now commence from the current estimated nuclear fuel loading date for each unit, which is December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4, rather than the original guaranteed substantial completion dates under the Vogtle 3 and 4 Agreement; and (v) provide that Georgia Power, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million , of which approximately $120 million has been paid previously under the dispute resolution procedures of the Vogtle 3 and 4 Agreement. Further, subsequent to December 31, 2015, Georgia Power paid approximately $121 million under the terms of the Contractor Settlement Agreement. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs were reflected in Georgia Power's previously disclosed in-service cost estimate.

Further, as part of the settlement: (i) Westinghouse has engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor; and (ii) the Vogtle Owners, CB&I, and The Shaw Group Inc. have entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On January 21, 2016, Georgia Power submitted the Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement to the Georgia PSC for its review. On February 2, 2016, the Georgia PSC ordered Georgia Power to file supplemental information by April 5, 2016 in support of the Contractor Settlement Agreement and Georgia Power's position that all construction costs to date have been prudently incurred and that the current estimated in-service capital cost and schedule are reasonable. Following Georgia Power's filing under the order, the Georgia PSC Staff (Staff) will conduct a review of all costs incurred related to Plant Vogtle Units 3 and 4, the schedule for completion of Plant Vogtle Units 3 and 4, and the Contractor Settlement Agreement and the Staff is authorized to engage in related settlement discussions with Georgia Power and any intervenors. The order provides that the Staff is required to report to the Georgia PSC by October 5, 2016 with respect to the status of its review and any settlement-related negotiations.

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

Income Tax Matters

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 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 50% bonus depreciation is expected to result in approximately $855 million of positive cash flows for the 2015 tax year and approximately $1.3 billion for the 2016 tax year, which may not all be realized in 2016 due to a projected net operating loss for the 2016 tax year. Approximately $360 million of this benefit is dependent upon placing the remainder of the Kemper IGCC in service in 2016. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Tax Credits

The IRS allocated $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power 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 April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. As a result of the schedule extension for the Kemper IGCC, the Phase II credits have been recaptured. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

In 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. The PATH Act extended the ITC with a phase out that allows for 30% ITC for solar projects that commence construction by December 31, 2019; 26% ITC for solar projects that commence construction in 2020; 22% ITC for solar projects that commence construction in 2021; and the permanent 10% ITC for solar projects that commence construction on or after January 1, 2022. In addition, the PATH Act extended the production tax credit (PTC) for wind projects with a phase out that allows for 100% PTC for wind projects that commence construction in 2016; 80% PTC for wind projects that commence construction in 2017; 60% PTC for wind projects that commence construction in 2018; and 40% PTC for wind projects that commence construction in 2019. The Company has received ITCs and PTCs in connection with investments in solar, wind, and biomass facilities at Southern Power and Georgia Power. See Note 1 to the financial statements under "Income and Other Taxes" for additional information regarding credits amortized and the tax benefit related to basis differences.

Section 174 Research and Experimental Deduction

Southern Company reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations for 2013, 2014, and 2015. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures. Due to the uncertainty related to this tax position, Southern Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $423 million as of December 31, 2015 . See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. Also see "Bonus Depreciation" herein. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Southern Company and its subsidiaries are involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as 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 Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern 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.

Through 2015, capacity revenues represented the majority of Gulf Power's wholesale earnings. Gulf Power had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 (205 MWs) and these capacity revenues represented 82% of Gulf Power's total wholesale capacity revenues for 2015. Due to the expiration of a wholesale contract at the end of 2015 and future expiration dates of the remaining wholesale contracts for the unit, Gulf Power currently has contracts to cover 34% of the unit for 2016 and 27% of the unit through 2019. Gulf Power is actively evaluating alternatives relating to this asset, including replacement wholesale contracts. The expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts are not expected to have a material impact on Southern Company's earnings. In the event some portion of the Gulf Power's ownership of Plant Scherer Unit 3 is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the Southern Company power pool or into the wholesale market. The ultimate outcome of this matter cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

Southern Company's traditional operating companies, which comprised approximately 94% of Southern Company's total operating revenues for 2015 , are subject to retail regulation by their respective state PSCs and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional operating companies are permitted to charge customers based on allowable costs, including a reasonable ROE. As a result, the traditional operating companies apply accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the traditional operating companies; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

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

During 2015 , Mississippi Power 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 DOE Grants and excluding the Cost Cap Exceptions. Mississippi Power 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 DOE Grants and excluding the Cost Cap Exceptions.

As a result of the revisions to the cost estimate, Southern Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $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, and $540 million ($333 million after tax) in the first quarter 2013. In the aggregate, Southern Company has incurred charges of $2.4 billion ($1.5 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2015 .

Mississippi Power has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and these changes could be material. Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, 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 for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including, but not limited to, additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

Mississippi Power's revised cost estimate includes costs through August 31, 2016. Any extension of the in-service date beyond August 31, 2016 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 August 31, 2016 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 $13 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 $2 million per month.

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 Southern Company's results of operations, Southern 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 the decommissioning of nuclear facilities – Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2 – and facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Southern Company system has retirement obligations related to various landfill sites, asbestos removal, mine reclamation, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the 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.

As a result of the final CCR Rule discussed above, Alabama Power, Gulf Power, and Mississippi Power recorded new AROs for facilities that are subject to the CCR Rule. Georgia Power had previously recorded AROs as a result of state requirements in Georgia which closely align with the requirements of the CCR Rule. The cost estimates 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 in place or by other methods. 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, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the traditional operating companies expect to continue to periodically update these estimates.

Given the significant judgment involved in estimating AROs, Southern 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" and "Nuclear Decommissioning" for additional information.

Pension and Other Postretirement Benefits

Southern Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, 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 Southern 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 Southern Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. Southern Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to Southern Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, Southern Company discounts the future related cash flows using a single-point discount rate for each plan 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, Southern 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, Southern Company has 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 will decrease by approximately $96 million in 2016.

The following table illustrates the sensitivity to changes in Southern Company's long-term assumptions with respect to the assumed discount rate, the assumed salaries, and the assumed long-term rate of return on plan assets:

Change in Assumption	Increase/(Decrease) in Total Benefit Expense for 2016	Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2015	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2015
		(in millions)	
25 basis point change in discount rate	$30/$(29)	$353/$(335)	$56/$(53)
25 basis point change in salaries	$12/$(11)	$91/$(88)	$–/$–
25 basis point change in long-term return on plan assets	$25/$(25)	N/A	N/A

N/A – Not applicable

Contingent Obligations

Southern 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. Southern 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 Southern Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers,* revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. Southern Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $202 million as of December 31, 2014. These debt issuance costs were previously presented within unamortized debt issuance expense. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of Southern Company. See Notes 6 and 10 to the financial statements for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), effective for fiscal years beginning after December 15, 2015. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of Southern Company. See Notes 2 and 10 to the financial statements for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from deferred income taxes, current of $506 million, with $488 million to non-current accumulated deferred income taxes and $18 million to other deferred charges, as well as $2 million from accrued income taxes to non-current accumulated deferred income taxes in Southern Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of Southern Company. See Note 5 to the financial statements for disclosures impacted by ASU 2015-17.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in 2015 and 2014 were negatively affected by revisions to the cost estimate for the Kemper IGCC; however, Southern Company's financial condition remained stable at December 31, 2015 and December 31, 2014. Through December 31, 2015 , Southern Company has incurred non-recoverable cash expenditures of $1.95 billion and is expected to incur approximately $0.46 billion in additional non-recoverable cash expenditures through completion of the Kemper IGCC.

Southern Company's cash requirements primarily consist of funding ongoing operations, funding the cash consideration for the Merger, common stock dividends, capital expenditures, and debt maturities. The Southern Company system's capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing facilities, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Southern Company system's cash needs. For the three-year period from 2016 through 2018 , Southern Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Southern Company system's projected capital expenditures in that period include investments to build new generation facilities, to maintain existing generation facilities, to add environmental modifications to existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. Southern Company plans to finance future cash needs in excess of its operating cash flows primarily by accessing borrowings from financial institutions and through debt and equity issuances in the capital markets. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit arrangements to meet future capital and liquidity needs. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Bonus Depreciation" and "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Southern Company's investments in the qualified pension plan and the nuclear decommissioning trust funds decreased in value as of December 31, 2015 as compared to December 31, 2014 . No contributions to the qualified pension plan were made for the year ended December 31, 2015 , and no mandatory contributions to the qualified pension plan are anticipated during 2016 . See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities in 2015 totaled $6.3 billion , an increase of $459 million from 2014 . The increase in net cash provided from operating activities was primarily due to an increase in fuel cost recovery, partially offset by the timing of vendor payments. Net cash provided from operating activities in 2014 totaled $5.8 billion , a decrease of $282 million from 2013 . Significant changes in operating cash flow for 2014 as compared to 2013 included $500 million of voluntary contributions to the qualified pension plan and an increase in receivables due to under recovered fuel costs, partially offset by an increase in accrued compensation.

Net cash used for investing activities in 2015 , 2014 , and 2013 totaled $7.3 billion , $6.4 billion , and $5.7 billion , respectively. The cash used for investing activities in each of these years was primarily due to gross property additions for installation of equipment to comply with environmental standards, construction of generation, transmission, and distribution facilities, acquisitions of solar facilities, and purchases of nuclear fuel.

Net cash provided from financing activities totaled $1.7 billion in 2015 due to issuances of long-term debt and common stock and an increase in short-term debt, partially offset by common stock dividend payments and redemptions of long-term debt and preferred and preference stock. Net cash provided from financing activities totaled $644 million in 2014 due to issuances of long-term debt and common stock, partially offset by common stock dividend payments, redemptions of long-term debt, and a reduction in short-term debt. Net cash used for financing activities totaled $324 million in 2013 due to redemptions of long-term debt and payments of common stock dividends, partially offset by issuances of long-term debt and common stock and an increase in notes payable. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2015 included increases of $4.9 billion in plant in service, net of depreciation and $1.3 billion in construction work in progress for the installation of equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities; increases of $0.7 billion in other regulatory assets, deferred and $1.6 billion in AROs primarily resulting from impacts of the CCR Rule; an increase of $3.4 billion in short-term and long-term debt to fund the subsidiaries' continuous construction programs and for other general corporate purposes; and an increase of $1.2 billion in accumulated deferred income taxes primarily as a result of bonus depreciation. See Note 1 and Note 5 to the financial statements for additional information regarding AROs and deferred income taxes, respectively.

At the end of 2015 , the market price of Southern Company's common stock was $46.79 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $22.59 per share, representing a market-to-book value ratio of 207 %, compared to $49.11, $21.98, and 223%, respectively, at the end of 2014 .

Sources of Capital

Southern Company intends to meet its future capital needs through operating cash flows, short-term debt, term loans, and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital and debt issuances in 2016 , as well as in subsequent years, will be contingent on Southern Company's investment opportunities and the Southern Company system's capital requirements.

Except as described herein, the traditional operating companies and Southern Power plan to obtain the funds required for construction and other purposes from operating cash flows, external security issuances, term loans, short-term borrowings, and equity contributions or loans from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

In addition, Georgia Power may make borrowings through a loan guarantee agreement (Loan Guarantee Agreement), between Georgia Power and the DOE, the proceeds of which may be used to reimburse Georgia Power for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Loan Guarantee Agreement (Eligible Project Costs). Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the FFB. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement and Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

Eligible Project Costs incurred through December 31, 2015 would allow for borrowings of up to $2.3 billion under the FFB Credit Facility, of which Georgia Power has borrowed $2.2 billion .

Mississippi Power received $245 million of DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for the commercial operation of the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

Mississippi Power expects the Kemper IGCC to qualify for additional DOE grants included in the recently passed Consolidated Appropriations Act of 2015, which are expected to be used to reduce future rate impacts for customers. The ultimate outcome of this matter cannot be determined at this time.

The issuance of securities by the traditional operating companies is generally subject to the approval of the applicable state PSC. The issuance of all securities by Mississippi Power and short-term securities by Georgia Power is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Company and certain of its subsidiaries file registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the securities registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

As of December 31, 2015 , Southern Company's current liabilities exceeded current assets by $2.6 billion , primarily due to long-term debt that is due within one year of $2.7 billion , including approximately $0.5 billion at the parent company, $0.2 billion at Alabama Power, $0.7 billion at Georgia Power, $0.1 billion at Gulf Power, $0.7 billion at Mississippi Power, and $0.4 billion at Southern Power. In addition, Mississippi Power has $0.5 billion in short-term bank loans scheduled to mature on April 1, 2016. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets and financial institutions. Southern Company, the traditional operating companies, and Southern Power intend to utilize operating cash flows, as well as commercial paper, lines of credit, bank notes, and securities issuances, as market conditions permit, as well as, under certain circumstances for the traditional operating companies and Southern Power, equity contributions and/or loans from Southern Company to meet their short-term capital needs.

The financial condition of Mississippi Power and its ability to obtain financing needed for normal business operations and completion of construction and start-up of the Kemper IGCC were adversely affected by the return of approximately $301 million of interest bearing refundable deposits to SMEPA in June 2015 in connection with the termination of the APA, the required refund of approximately $371 million of Mirror CWIP rate collections, including associated carrying costs, the termination of the Mirror CWIP rate, and the required recapture of Phase II tax credits. On December 3, 2015, the Mississippi PSC approved the In-Service Asset Rate Order which, among other things, provides for retail rate recovery of an annual revenue requirement of approximately $126 million which became effective on December 17, 2015. Mississippi Power plans to refinance its 2016 debt maturities with bank term loans and to obtain the funds required for construction and other purposes from operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

At December 31, 2015 , Southern Company and its subsidiaries had approximately $1.4 billion of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2015 were as follows:

	Expires						Executable Term Loans		Due Within One Year	
Company	2016	2017	2018	2020	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)				*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company [(a)]	$ —	$ —	$ 1,000	$ 1,250	$ 2,250	$ 2,250	$ —	$ —	$ —	$ —
Alabama Power	40	—	500	800	1,340	1,340	—	—	—	40
Georgia Power	—	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	80	30	165	—	275	275	50	—	50	30
Mississippi Power	220	—	—	—	220	195	30	15	45	175
Southern Power [(b)]	—	—	—	600	600	566	—	—	—	—
Other	70	—	—	—	70	70	—	—	—	70
Total	$ 410	$ 30	$ 1,665	$ 4,400	$ 6,505	$ 6,428	$ 80	$ 15	$ 95	$ 315

(a) Excludes the $8.1 billion Bridge Agreement entered into in September 2015 that will be funded only to the extent necessary to provide financing for the Merger as discussed herein.

(b) Excludes credit agreements (Project Credit Facilities) assumed with the acquisition of certain solar facilities, which are non-recourse to Southern Power Company, the proceeds of which are being used to finance project costs related to such solar facilities currently under construction. See Note 12 to the financial statements under "Southern Power" for additional information.

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

As reflected in the table above, in August 2015, Southern Company, Alabama Power, Georgia Power, and Southern Power Company each amended and restated their multi-year credit arrangements, which, among other things, extended the maturity dates from 2018 to 2020. Southern Company and Southern Power Company increased their borrowing ability under these arrangements to $1.25 billion from $1.0 billion and to $600 million from $500 million, respectively. Georgia Power increased its borrowing ability by $150 million under its facility maturing in 2020 and terminated its aggregate $150 million facilities maturing in 2016. In September 2015, Southern Company entered into an additional multi-year credit arrangement for $1 billion with a maturity date of 2018. Also in September 2015, Alabama Power entered into a new $500 million three-year credit arrangement which replaced a majority of Alabama Power's bilateral credit arrangements. In November 2015, Gulf Power amended and restated certain of its multi-year credit arrangements which, among other things, extended the maturity dates from 2016 to 2018.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross acceleration or cross default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the individual company. Such cross default provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness or guarantee obligations over a specified threshold. Such cross acceleration provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness, the payment of which was then accelerated. Southern Company, the traditional operating companies, and Southern Power Company are currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

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

A portion of the unused credit with banks is allocated to provide liquidity support to the traditional operating companies' pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2015 was approximately $1.8 billion . In addition, at December 31, 2015 , the traditional operating companies had approximately $181 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

Southern Company intends to initially fund the cash consideration for the Merger using a mix of debt and equity. Southern Company finances its capital needs on a portfolio basis and expects to issue approximately $8.0 billion in debt prior to closing the Merger and approximately $1.2 billion in equity during 2016. This capital is expected to provide funding for the Merger, Southern Power growth opportunities, and other Southern Company system capital projects. Southern Company expects to issue the debt to fund the Merger Consideration in several tranches including long-dated maturities. The amount of debt issued at each maturity will depend on prevailing market conditions at the time of the offering and other factors. In addition, Southern Company entered into the $8.1 billion Bridge Agreement on September 30, 2015 to provide financing for the Merger in the event long-term financing is not available.

The Bridge Agreement provides for total loan commitments in an aggregate amount of $8.1 billion to fund the payment of the cash consideration payable under the Merger Agreement and other cash payments required in connection with the consummation of the Merger, the Bridge Agreement and the borrowings thereunder, the other financing transactions related to the Merger, and the payment of fees and expenses incurred in connection with the foregoing. If funded, the loan under the Bridge Agreement will mature and be payable in full on the date that is 364 days after the funding of the commitments under the Bridge Agreement (Closing Date).

In connection with the Bridge Agreement, Southern Company will pay a ticking fee for the benefit of the lenders thereto, accruing from November 21, 2015, in an amount equal to 0.125% per annum of the aggregate commitments under the Bridge Agreement, which fee will accrue through the earlier of (i) the date of termination of the commitments and (ii) the Closing Date. Additionally, under the terms of the Bridge Agreement, Southern Company is required to pay certain customary fees to the lenders as set forth in related letters. As of December 31, 2015 , Southern Company had no outstanding loans under the Bridge Agreement.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above, excluding the Bridge Agreement. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Short-term borrowings are included in notes payable in the balance sheets.

Details of short-term borrowings 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 Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2015:					
Commercial paper	**$ 740**	**0.7%**	**$ 842**	**0.4%**	**$ 1,563**
Short-term bank debt	**500**	**1.4%**	**444**	**1.1%**	**795**
Total	**$ 1,240**	**0.9%**	**$ 1,286**	**0.5%**	
December 31, 2014:					
Commercial paper	$ 803	0.3%	$ 754	0.2%	$ 1,582
Short-term bank debt	—	—%	98	0.8%	400
Total	$ 803	0.3%	$ 852	0.3%	
December 31, 2013:					
Commercial paper	$ 1,082	0.2%	$ 993	0.3%	$ 1,616
Short-term bank debt	400	0.9%	107	0.9%	400
Total	$ 1,482	0.4%	$ 1,100	0.3%	

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2015 , 2014 , and 2013 .

In addition to the short-term borrowings in the table above, the Project Credit Facilities had total amounts outstanding as of December 31, 2015 of $137 million at a weighted average interest rate of 2.0%. For the year ended December 31, 2015, the Project Credit Facilities had a maximum amount outstanding of $137 million, and an average amount outstanding of $13 million at a weighted average interest rate of 2.0%.

The Company believes the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, bank notes, and operating cash flows.

Financing Activities

During 2015 , Southern Company issued approximately 6.6 million shares of common stock primarily through the employee equity compensation plan and received proceeds of approximately $256 million . During the first nine months of 2015, all sales under the Southern Investment Plan and the Employee Savings Plan were funded with shares acquired on the open market by independent plan administrators. In October 2015, Southern Company began issuing shares of common stock through the Southern Investment Plan and the Employee Savings Plan. The Company may satisfy its obligations with respect to the plans in several ways, including through using newly issued shares or treasury shares or acquiring shares on the open market through the independent plan administrators.

On March 2, 2015, Southern Company announced a program to repurchase up to 20 million shares of Southern Company common stock to offset all or a portion of the incremental shares issued under its employee and director stock plans, including through stock option exercises, until December 31, 2017. Under this program, approximately 2.6 million shares were repurchased in 2015 at a total cost of approximately $115 million . No further repurchases under the program are anticipated.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2015 Annual Report

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the year ended December 31, 2015:

Company	Senior Note Issuances	Senior Note Maturities and Redemptions	Revenue Bond Issuances and Reofferings of Purchased Bonds [(a)]	Revenue Bond Maturities, Redemptions, and Repurchases	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities [(b)]
	(in millions)					
Southern Company	$ 600	$ 400	$ —	$ —	$ 1,400	$ —
Alabama Power	975	650	80	134	—	—
Georgia Power	500	1,175	409	267	1,000	6
Gulf Power	—	60	13	13	—	—
Mississippi Power	—	—	—	—	275	353
Southern Power	1,650	525	—	—	402	4
Other	—	—	—	—	—	17
Elimination [(c)]	—	—	—	—	(275)	—
Total	$ 3,725	$ 2,810	$ 502	$ 414	$ 2,802	$ 380

(a) Includes a reoffering by Alabama Power of $80.0 million aggregate principal amount of revenue bonds purchased and held since April 2015; reofferings by Georgia Power of $135.2 million, $104.6 million, and $65.0 million aggregate principal amount of revenue bonds purchased and held since 2010, 2013, and April 2015, respectively; and a reoffering by Gulf Power of $13.0 million aggregate principal amount of revenue bonds purchased and held in July 2015. Also includes repurchases and reofferings by Georgia Power of $94.6 million and $10.0 million aggregate principal amount of revenue bonds in August 2015 in connection with optional tenders.

(b) Includes reductions in capital lease obligations resulting from cash payments under capital leases.

(c) Intercompany loan from Southern Company to Mississippi Power eliminated in Southern Company's Consolidated Financial Statements.

In June 2015, Southern Company issued $600 million aggregate principal amount of Series 2015A 2.750% Senior Notes due June 15, 2020. The proceeds were used to pay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

In September 2015, Southern Company entered into a $400 million aggregate principal amount 18-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes.

Also in September 2015, Southern Company repaid at maturity $400 million aggregate principal amount of its Series 2010A 2.375% Senior Notes due September 15, 2015.

In October 2015, Southern Company issued $1.0 billion aggregate principal amount of Series 2015A 6.25% Junior Subordinated Notes due October 15, 2075. The proceeds were used to pay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

In November and December 2015, Southern Company entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to anticipated debt issuances. The notional amount of the swaps totaled $2 billion. Subsequent to December 31, 2015, Southern Company entered into an additional $700 million notional amount of forward-starting interest rate swaps.

Except as described herein, Southern Company's subsidiaries used the proceeds of the debt issuances shown in the table above for their redemptions and maturities shown in the table above, to repay short-term indebtedness, and for general corporate purposes, including their continuous construction programs and, for Southern Power, its growth strategy.

A portion of the proceeds of Alabama Power's senior note issuances were used in May 2015 to redeem 6.48 million shares ($162 million aggregate stated capital) of Alabama Power's 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, 4.0 million shares ($100 million aggregate stated capital) of Alabama Power's 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and 6.0 million shares ($150 million aggregate stated capital) of Alabama Power's 5.625% Series Preference Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date.

Georgia Power's "Other Long-Term Debt Issuances" reflected in the table above include borrowings in June and December 2015 under the FFB Credit Facility in an aggregate principal amount of $600 million and $400 million, respectively. The interest rate applicable to the $600 million principal amount is 3.283% and the interest rate applicable to the $400 million principal amount is 3.072%, both for an interest period that extends to the final maturity date of February 20, 2044. The proceeds were used to reimburse Georgia Power for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4.

In March 2015, Georgia Power entered into a $250 million aggregate principal amount three-month floating rate bank loan bearing interest based on one-month LIBOR. The loan was repaid at maturity.

In April 2015, Mississippi Power entered into two short-term floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million, bearing interest based on one-month LIBOR. A portion of the proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million. Mississippi Power also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016.

In addition to the amounts reflected in the table above, Mississippi Power previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest in connection with the termination of the APA. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, Mississippi Power issued a floating rate promissory note to Southern Company in an aggregate principal amount of approximately $301 million bearing interest based on one-month LIBOR, which matures on December 1, 2017. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" for additional information.

In June 2015, Gulf Power entered into a $40 million aggregate principal amount three-month floating rate bank loan bearing interest based on one-month LIBOR. The loan was repaid at maturity.

In October 2015, Gulf Power entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $80 million.

Subsequent to December 31, 2015, Alabama Power issued $400 million aggregate principal amount of Series 2016A 4.30% Senior Notes due January 2, 2046. The proceeds were used to repay at maturity $200 million aggregate principal amount of its Series FF 5.20% Senior Notes due January 15, 2016 and for general corporate purposes, including Alabama Power's continuous construction program.

Subsequent to December 31, 2015, Southern Power borrowed $182 million pursuant to the Project Credit Facilities at a weighted average interest rate of 2.0%.

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

Credit Rating Risk

Southern Company and its subsidiaries do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and/or Baa2 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, transmission, interest rate management, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at December 31, 2015 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and/or Baa2	$ 12
At BBB- and/or Baa3	$ 508
Below BBB- and/or Baa3	$ 2,432

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 Southern Company and its subsidiaries to access capital markets and would be likely to impact the cost at which they do so.

On June 5, 2015, Fitch Ratings, Inc. (Fitch) downgraded the long-term issuer default rating of Mississippi Power to BBB+ from A-. Fitch maintained the negative ratings outlook for Mississippi Power and revised the ratings outlook for Southern Company from stable to negative.

On August 14, 2015, Moody's downgraded the senior unsecured debt rating of Mississippi Power to Baa2 from Baa1. Moody's maintained the negative ratings outlook for Mississippi Power.

On August 17, 2015, S&P downgraded the consolidated long-term issuer rating of Southern Company (including Alabama Power, Georgia Power, and Gulf Power) to A- from A. Also on August 17, 2015, S&P downgraded the issuer rating of Mississippi Power to BBB+ from A. S&P revised its credit rating outlook for Southern Company and the traditional operating companies to stable from negative. Separately, on August 24, 2015, S&P revised its credit rating outlook for Southern Company, the traditional operating companies, and Southern Power Company from stable to negative following the announcement of the Merger.

Also following the announcement of the Merger, on August 24, 2015, Moody's affirmed the rating of Southern Company and revised its credit rating outlook from stable to negative. On the same date, Fitch placed the ratings of Southern Company on ratings watch negative.

On November 5, 2015, Moody's downgraded the senior unsecured debt rating of Mississippi Power to Baa3 from Baa2. Moody's maintained the negative ratings outlook for Mississippi Power.

Market Price Risk

The Southern Company system is exposed to market risks, primarily commodity price risk and interest rate risk. The Southern Company system may also occasionally have limited exposure to foreign currency exchange rates. To manage the volatility attributable to these exposures, the applicable 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 applicable company's policies in areas such as counterparty exposure and risk management practices. The Southern Company system's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, Southern Company and certain of its subsidiaries enter into derivatives that have been designated as hedges. Derivatives, that have been designated as hedges, outstanding at December 31, 2015 have a notional amount of $4.2 billion, of which $2.3 billion are to mitigate interest rate volatility related to projected debt financings in 2016. The remaining $1.9 billion are related to existing fixed and floating rate obligations. The weighted average interest rate on $5.2 billion of long-term variable interest rate exposure at January 1, 2016 was 1.19%. If Southern 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 $52 million at January 1, 2016 . See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies and Southern Power may enter into physical fixed-price or heat rate 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; however, a significant portion of contracts are priced at market. The traditional operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs. Southern Company had no material change in market risk exposure for the year ended December 31, 2015 when compared to the year ended December 31, 2014 .

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:

	2015 Changes	2014 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (188)**	$ (32)
Contracts realized or settled:		
Swaps realized or settled	**121**	(9)
Options realized or settled	**21**	6
Current period changes (*) :		
Swaps	**(152)**	(131)
Options	**(15)**	(22)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (213)**	$ (188)

(*) 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 for the years ended December 31 were as follows:

	2015	2014
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**168**	200
Commodity – Natural gas options	**56**	44
Total hedge volume	**224**	244

The weighted average swap contract cost above market prices was approximately $1.14 per mmBtu as of December 31, 2015 and $0.84 per mmBtu as of December 31, 2014 . The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the traditional operating companies' fuel cost recovery clauses.

At December 31, 2015 and 2014 , substantially all of the Southern Company system's energy-related derivative contracts were designated as regulatory hedges and were related to the applicable 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 energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

Southern Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 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, 2015 were as follows:

	Fair Value Measurements December 31, 2015			
	Total Fair Value	Maturity Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$ —	$ —
Level 2	213	126	82	5
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ 213	$ 126	$ 82	$ 5

Southern Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. Southern Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, Southern Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Southern Company performs periodic reviews of its leveraged lease transactions, both domestic and international, and the creditworthiness of the lessees, including a review of the value of the underlying leased assets and the credit ratings of the lessees. Southern Company's domestic lease transactions generally do not have any credit enhancement mechanisms; however, the lessees in its international lease transactions have pledged various deposits as additional security to secure the obligations. The lessees in the Company's international lease transactions are also required to provide additional collateral in the event of a credit downgrade below a certain level.

Capital Requirements and Contractual Obligations

The Southern Company system's construction program is currently estimated to total $7.3 billion for 2016 , $5.2 billion for 2017 , and $5.5 billion for 2018 . These amounts include expenditures of approximately $0.6 billion related to the construction and start-up of the Kemper IGCC in 2016; $0.6 billion, $0.7 billion, and $0.4 billion to continue construction on Plant Vogtle Units 3 and 4 in 2016, 2017, and 2018, respectively; and $2.2 billion, $0.9 billion, and $1.4 billion for acquisitions and/or construction of new Southern Power generating facilities in 2016, 2017, and 2018, respectively. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.7 billion , $0.5 billion , and $0.6 billion for 2016 , 2017 , and 2018 , respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" herein for additional information.

The Southern Company system also anticipates costs associated with closure in place or by other methods, and ground water monitoring of ash ponds in accordance with the CCR Rule, which are not reflected in the capital expenditures above as these costs are associated with the Company's ARO liabilities. These costs, which could change as the Southern Company system continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance, are estimated to be approximately $0.2 billion, $0.2 billion, and $0.3 billion for 2016, 2017, and 2018, respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; 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; 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; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy. See Note 12 to the financial statements under "Southern Power" for additional information regarding Southern Power's plant acquisitions. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for information regarding additional factors that may impact construction expenditures.

In addition, the construction program includes the development and construction of new generating facilities with designs that have not been finalized or previously constructed, including 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, 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 any PSC).

In addition to the Merger Consideration to be paid by Southern Company at the Effective Time, in connection with the Merger, Southern Company will also assume AGL Resources' outstanding indebtedness (approximately $4.8 billion at December 31, 2015). See OVERVIEW herein for additional information regarding the Merger, including the Merger Consideration, as well as Note 12 to the financial statements.

As a result of NRC requirements, Alabama Power and Georgia Power have external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, Southern Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the traditional operating companies' respective regulatory commissions.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, unrecognized tax benefits, other purchase commitments, and trusts are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2016	2017-2018	2019-2020	After 2020	Total
			(in millions)		
Long-term debt [a] —					
Principal	$ 2,642	$ 4,128	$ 2,572	$ 18,090	$ 27,432
Interest	997	1,794	1,576	14,948	19,315
Preferred and preference stock dividends [b]	45	91	91	—	227
Financial derivative obligations [c]	156	83	5	—	244
Operating leases [d]	121	184	114	706	1,125
Capital leases [d]	32	28	23	63	146
Unrecognized tax benefits [e]	9	424	—	—	433
Purchase commitments —					
Capital [f]	6,906	9,780	—	—	16,686
Fuel [g]	3,201	4,473	2,566	7,378	17,618
Purchased power [h]	380	803	840	3,762	5,785
Other [i]	281	637	482	1,661	3,061
Trusts —					
Nuclear decommissioning [j]	5	11	11	104	131
Pension and other postretirement benefit plans [k]	117	232	—	—	349
Total	$ 14,892	$ 22,668	$ 8,280	$ 46,712	$ 92,552

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information. Southern Company and its subsidiaries plan 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, 2016 , 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) Represents preferred and preference stock of subsidiaries. Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(c) Includes derivative liabilities related to cash flow hedges of forecasted debt, as well as energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.

(d) Excludes PPAs that are accounted for as leases and included in "Purchased power."

(e) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(f) The Southern Company system provides estimated capital expenditures for a three-year period, including capital expenditures associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected in "Fuel" and "Other," respectively. At December 31, 2015 , significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

(g) Primarily includes commitments to purchase coal, nuclear fuel, 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, 2015 .

(h) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. Includes a total of $304 million of biomass PPAs that is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Georgia Power – Renewables Development" herein for additional information.

(i) Includes long-term service agreements, contracts for the procurement of limestone, and operation and maintenance agreements. Long-term service agreements include price escalation based on inflation indices.

(j) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP for Georgia Power. Alabama Power also has external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

(k) The Southern Company system forecasts contributions to the pension and other postretirement benefit plans over a three-year period. Southern 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 corporate assets of Southern Company's subsidiaries. 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 corporate assets of Southern Company's subsidiaries.

Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2015 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, the potential financing of the Merger, the expected timing of the completion of the Merger, the strategic goals for the wholesale business, economic recovery, 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 , postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of acquisitions, construction projects, and changing fuel sources, 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, 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 legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws regulating emissions, discharges, and disposal to air, water, and land , and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including , without limitation, IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the 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 and construction 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, 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 any 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 Southern Company's employee and retiree benefit plans and the Southern Company system's nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;
- 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;
- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;

- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the expected timing, likelihood, and benefits of completion of the Merger, including the failure to receive, on a timely basis or otherwise, the required approvals by government or regulatory agencies (including the terms of such approvals), the possibility that long-term financing for the Merger may not be put in place prior to the closing, the risk that a condition to closing of the Merger or funding of the Bridge Agreement may not be satisfied, the possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected, the possibility that costs related to the integration of Southern Company and AGL Resources will be greater than expected, the credit ratings of the combined company or its subsidiaries may be different from what the parties expect, the ability to retain and hire key personnel and maintain relationships with customers, suppliers, or other business partners, the diversion of management time on Merger-related issues, and the impact of legislative, regulatory, and competitive changes;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system'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 Southern Company's and any of its subsidiaries' 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 currency exchange rates, counterparty performance, and the economy in general , as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's subsidiaries to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system'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 Southern Company from time to time with the SEC.

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

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2015 , 2014 , and 2013
Southern Company and Subsidiary Companies 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 14,987**	$ 15,550	$ 14,541
Wholesale revenues	**1,798**	2,184	1,855
Other electric revenues	**657**	672	639
Other revenues	**47**	61	52
Total operating revenues	**17,489**	18,467	17,087
Operating Expenses:			
Fuel	**4,750**	6,005	5,510
Purchased power	**645**	672	461
Other operations and maintenance	**4,416**	4,354	3,846
Depreciation and amortization	**2,034**	1,945	1,901
Taxes other than income taxes	**997**	981	934
Estimated loss on Kemper IGCC	**365**	868	1,180
Total operating expenses	**13,207**	14,825	13,832
Operating Income	**4,282**	3,642	3,255
Other Income and (Expense):			
Allowance for equity funds used during construction	**226**	245	190
Interest income	**23**	19	19
Interest expense, net of amounts capitalized	**(840)**	(835)	(824)
Other income (expense), net	**(62)**	(63)	(81)
Total other income and (expense)	**(653)**	(634)	(696)
Earnings Before Income Taxes	**3,629**	3,008	2,559
Income taxes	**1,194**	977	849
Consolidated Net Income	**2,435**	2,031	1,710
Less:			
Dividends on preferred and preference stock of subsidiaries	**54**	68	66
Net income attributable to noncontrolling interests	**14**	—	—
Consolidated Net Income Attributable to Southern Company	**$ 2,367**	$ 1,963	$ 1,644
Common Stock Data:			
Earnings per share (EPS) —			
Basic EPS	**$ 2.60**	$ 2.19	$ 1.88
Diluted EPS	**2.59**	2.18	1.87
Average number of shares of common stock outstanding — (in millions)			
Basic	**910**	897	877
Diluted	**914**	901	881

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2015 , 2014 , and 2013
Southern Company and Subsidiary Companies 2015 Annual Report

	2015	2014	2013
		(in millions)	
Consolidated Net Income	**$ 2,435**	$ 2,031	$ 1,710
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(8), $(6), and $-, respectively	**(13)**	(10)	—
Reclassification adjustment for amounts included in net income, net of tax of $4, $3, and $5, respectively	**6**	5	9
Marketable securities:			
Change in fair value, net of tax of $-, $-, and $(2), respectively	**—**	—	(3)
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $(1), $(32), and $22, respectively	**(2)**	(51)	36
Reclassification adjustment for amounts included in net income, net of tax of $4, $2, and $4, respectively	**7**	3	6
Total other comprehensive income (loss)	**(2)**	(53)	48
Less:			
Dividends on preferred and preference stock of subsidiaries	**54**	68	66
Comprehensive income attributable to noncontrolling interests	**14**	—	—
Consolidated Comprehensive Income Attributable to Southern Company	**$ 2,365**	$ 1,910	$ 1,692

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2015 , 2014 , and 2013
Southern Company and Subsidiary Companies 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Activities:			
Consolidated net income	**$ 2,435**	$ 2,031	$ 1,710
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	**2,395**	2,293	2,298
Deferred income taxes	**1,404**	709	496
Investment tax credits	**(48)**	35	302
Allowance for equity funds used during construction	**(226)**	(245)	(190)
Pension, postretirement, and other employee benefits	**76**	(515)	131
Stock based compensation expense	**99**	63	59
Estimated loss on Kemper IGCC	**365**	868	1,180
Income taxes receivable, non-current	**(413)**	—	—
Other, net	**(39)**	(39)	(41)
Changes in certain current assets and liabilities —			
-Receivables	**243**	(352)	(153)
-Fossil fuel stock	**61**	408	481
-Materials and supplies	**(44)**	(67)	36
-Other current assets	**(108)**	(57)	(11)
-Accounts payable	**(353)**	267	72
-Accrued taxes	**352**	(105)	(85)
-Accrued compensation	**(41)**	255	(138)
-Retail fuel cost over recovery — short-term	**289**	(23)	(66)
-Mirror CWIP	**(271)**	180	—
-Other current liabilities	**98**	109	16
Net cash provided from operating activities	**6,274**	5,815	6,097
Investing Activities:			
Plant acquisitions	**(1,719)**	(731)	(132)
Property additions	**(5,674)**	(5,246)	(5,331)
Investment in restricted cash	**(160)**	(11)	(149)
Distribution of restricted cash	**154**	57	96
Nuclear decommissioning trust fund purchases	**(1,424)**	(916)	(986)
Nuclear decommissioning trust fund sales	**1,418**	914	984
Cost of removal, net of salvage	**(167)**	(170)	(131)
Change in construction payables, net	**402**	(107)	(126)
Prepaid long-term service agreement	**(197)**	(181)	(91)
Other investing activities	**87**	(17)	124
Net cash used for investing activities	**(7,280)**	(6,408)	(5,742)
Financing Activities:			
Increase (decrease) in notes payable, net	**73**	(676)	662
Proceeds —			
Long-term debt issuances	**7,029**	3,169	2,938
Interest-bearing refundable deposit	**—**	125	—
Common stock issuances	**256**	806	695
Short-term borrowings	**755**	—	—
Redemptions and repurchases —			
Long-term debt	**(3,604)**	(816)	(2,830)
Common stock repurchased	**(115)**	(5)	(20)
Interest-bearing refundable deposits	**(275)**	—	—

Preferred and preference stock	**(412)**	—	—
Short-term borrowings	**(255)**	—	—
Capital contributions from noncontrolling interests	**341**	8	17
Payment of common stock dividends	**(1,959)**	(1,866)	(1,762)
Payment of dividends on preferred and preference stock of subsidiaries	**(59)**	(68)	(66)
Other financing activities	**(75)**	(33)	42
Net cash provided from (used for) financing activities	**1,700**	644	(324)
Net Change in Cash and Cash Equivalents	**694**	51	31
Cash and Cash Equivalents at Beginning of Year	**710**	659	628
Cash and Cash Equivalents at End of Year	**$ 1,404**	$ 710	$ 659

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2015 and 2014
Southern Company and Subsidiary Companies 2015 Annual Report

Assets	**2015**	2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 1,404**	$ 710
Receivables —		
Customer accounts receivable	**1,058**	1,090
Unbilled revenues	**397**	432
Under recovered regulatory clause revenues	**63**	136
Other accounts and notes receivable	**398**	307
Accumulated provision for uncollectible accounts	**(13)**	(18)
Income taxes receivable, current	**144**	—
Fossil fuel stock, at average cost	**868**	930
Materials and supplies, at average cost	**1,061**	1,039
Vacation pay	**178**	177
Prepaid expenses	**495**	665
Other regulatory assets, current	**402**	346
Other current assets	**71**	50
Total current assets	**6,526**	5,864
Property, Plant, and Equipment:		
In service	**75,118**	70,013
Less accumulated depreciation	**24,253**	24,059
Plant in service, net of depreciation	**50,865**	45,954
Other utility plant, net	**233**	211
Nuclear fuel, at amortized cost	**934**	911
Construction work in progress	**9,082**	7,792
Total property, plant, and equipment	**61,114**	54,868
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**1,512**	1,546
Leveraged leases	**755**	743
Miscellaneous property and investments	**485**	203
Total other property and investments	**2,752**	2,492
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**1,560**	1,510
Unamortized loss on reacquired debt	**227**	243
Other regulatory assets, deferred	**4,989**	4,334
Income taxes receivable, non-current	**413**	—
Other deferred charges and assets	**737**	922
Total deferred charges and other assets	**7,926**	7,009
Total Assets	**$ 78,318**	$ 70,233

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

CONSOLIDATED BALANCE SHEETS
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Liabilities and Stockholders' Equity	**2015**	2014
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 2,674**	$ 3,329
Interest-bearing refundable deposits	—	275
Notes payable	**1,376**	803
Accounts payable	**1,905**	1,593
Customer deposits	**404**	390
Accrued taxes —		
Accrued income taxes	**19**	149
Other accrued taxes	**484**	487
Accrued interest	**249**	295
Accrued vacation pay	**228**	223
Accrued compensation	**549**	576
Asset retirement obligations, current	**217**	32
Liabilities from risk management activities	**156**	138
Other regulatory liabilities, current	**278**	26
Mirror CWIP	—	271
Other current liabilities	**590**	374
Total current liabilities	**9,129**	8,961
Long-Term Debt (See accompanying statements)	**24,688**	20,644
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**12,322**	11,082
Deferred credits related to income taxes	**187**	192
Accumulated deferred investment tax credits	**1,219**	1,208
Employee benefit obligations	**2,582**	2,432
Asset retirement obligations, deferred	**3,542**	2,168
Unrecognized tax benefits	**370**	4
Other cost of removal obligations	**1,162**	1,215
Other regulatory liabilities, deferred	**254**	398
Other deferred credits and liabilities	**720**	589
Total deferred credits and other liabilities	**22,358**	19,288
Total Liabilities	**56,175**	48,893
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	**118**	375
Redeemable Noncontrolling Interests (See accompanying statements)	**43**	39
Total Stockholders' Equity (See accompanying statements)	**21,982**	20,926
Total Liabilities and Stockholders' Equity	**$ 78,318**	$ 70,233
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION
At December 31, 2015 and 2014
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		2015	2014	**2015**	2014
			(in millions)		*(percent of total)*
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Variable rate (3.43% at 1/1/16) due 2042		**$ 206**	$ 206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2015	0.55% to 5.25%	—	2,375		
2016	1.95% to 5.30%	**1,360**	1,360		
2017	1.30% to 5.90%	**1,995**	1,495		
2018	1.50% to 5.40%	**1,697**	850		
2019	2.15% to 5.55%	**1,176**	1,175		
2020	2.38% to 4.75%	**1,327**	425		
2021 through 2051	1.63% to 6.38%	**11,185**	10,150		
Variable rates (0.77% to 1.17% at 1/1/15) due 2015		—	775		
Variable rates (0.76% to 3.50% at 1/1/16) due 2016		**1,278**	450		
Variable rates (1.74% at 1/1/16) due 2017		**400**	—		
Total long-term senior notes and debt		**20,418**	19,055		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2019	4.55%	**25**	25		
2022 through 2049	0.28% to 5.15%	**1,509**	1,466		
Variable rates (0.03% to 0.04% at 1/1/15) due 2015		—	152		
Variable rate (0.22% at 1/1/16) due 2016		**4**	4		
Variable rate (0.05% to 0.06% at 1/1/16) due 2017		**36**	36		
Variable rate (0.16% at 1/1/16) due 2020		**7**	7		
Variable rates (0.01% to 0.27% at 1/1/16) due 2021 to 2053		**1,757**	1,559		
Plant Daniel revenue bonds (7.13%) due 2021		**270**	270		
FFB loans —					
3.00% to 3.86% due 2020		**37**	20		
3.00% to 3.86% due 2021 to 2044		**2,163**	1,180		
Junior subordinated notes (6.25%) due 2075		**1,000**	—		
Total other long-term debt		**6,808**	4,719		
Capitalized lease obligations		**146**	159		
Unamortized debt premium		**61**	69		
Unamortized debt discount		**(36)**	(33)		
Unamortized debt issuance expense		**(241)**	(202)		
Total long-term debt (annual interest requirement — $997 million)		**27,362**	23,973		
Less amount due within one year		**2,674**	3,329		
Long-term debt excluding amount due within one year		**24,688**	20,644	**52.6%**	49.2%

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2015 and 2014
Southern Company and Subsidiary Companies 2015 Annual Report

	2015	2014	**2015**	2014
		(in millions)		*(percent of total)*
Redeemable Preferred Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value — 4.20% to 5.44%				
Authorized — 20 million shares				
Outstanding — 1 million shares	**81**	81		
$1 par value —				
Authorized — 28 million shares				
Outstanding — $25 stated value	**37**	294		
— 2015: 5.83% — 2 million shares				
— 2014: 5.20% to 5.83% — 12 million shares				
Total redeemable preferred stock of subsidiaries (annual dividend requirement — $6 million)	**118**	375	**0.3**	0.9
Redeemable Noncontrolling Interests	**43**	39	**0.1**	0.1
Common Stockholders' Equity:				
Common stock, par value $5 per share —	**4,572**	4,539		
Authorized — 1.5 billion shares				
Issued — 2015: 915 million shares				
— 2014: 909 million shares				
Treasury — 2015: 3.4 million shares				
— 2014: 0.7 million shares				
Paid-in capital	**6,282**	5,955		
Treasury, at cost	**(142)**	(26)		
Retained earnings	**10,010**	9,609		
Accumulated other comprehensive loss	**(130)**	(128)		
Total common stockholders' equity	**20,592**	19,949	**44.0**	47.5
Preferred and Preference Stock of Subsidiaries and Noncontrolling Interests:				
Non-cumulative preferred stock				
$25 par value — 6.00% to 6.13%				
Authorized — 60 million shares				
Outstanding — 2 million shares	**45**	45		
Preference stock				
Authorized — 65 million shares				
Outstanding — $1 par value	**196**	343		
— 2015: 6.45% to 6.50% — 8 million shares (non-cumulative)				
— 2014: 5.63% to 6.50% — 14 million shares (non-cumulative)				
Outstanding — $100 par or stated value	**368**	368		
— 5.60% to 6.50% — 4 million shares (non-cumulative)				
Noncontrolling Interests	**781**	221		
Total preferred and preference stock of subsidiaries and noncontrolling interests (annual dividend requirement — $39 million)	**1,390**	977	**3.0**	2.3
Total stockholders' equity	**21,982**	20,926		
Total Capitalization	**$ 46,831**	$ 41,984	**100.0%**	100.0%

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2015 , 2014 , and 2013
Southern Company and Subsidiary Companies 2015 Annual Report

	Southern Company Common Stockholders' Equity										
	Number of Common Shares		Common Stock								
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Preferred and Preference Stock of Subsidiaries	Noncontrolling Interests	Total
	(in thousands)		*(in millions)*							
Balance at December 31, 2012	877,803	(10,035)	$4,389	$ 4,855	$ (450)	$ 9,626	$ (123)	$ 707	$ —	$ 19,004
Consolidated net income attributable to Southern Company	—	—	—	—	—	1,644	—	—	—	1,644
Other comprehensive income (loss)	—	—	—	—	—	—	48	—	—	48
Stock issued	14,930	4,443	72	441	203	—	—	49	—	765
Stock-based compensation	—	—	—	65	—	—	—	—	—	65
Cash dividends of $2.0125 per share	—	—	—	—	—	(1,762)	—	—	—	(1,762)
Other	—	(55)	—	1	(3)	2	—	—	—	—
Balance at December 31, 2013	892,733	(5,647)	4,461	5,362	(250)	9,510	(75)	756	—	19,764
Consolidated net income attributable to Southern Company	—	—	—	—	—	1,963	—	—	—	1,963
Other comprehensive income (loss)	—	—	—	—	—	—	(53)	—	—	(53)
Stock issued	15,769	4,996	78	501	227	—	—	—	—	806
Stock-based compensation	—	—	—	86	—	—	—	—	—	86
Cash dividends of $2.0825 per share	—	—	—	—	—	(1,866)	—	—	—	(1,866)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	221	221
Net income (loss) attributable to noncontrolling interests	—	—	—	—	—	—	—	—	(2)	(2)
Other	—	(74)	—	6	(3)	2	—	—	2	7
Balance at December 31, 2014	**908,502**	**(725)**	**4,539**	**5,955**	**(26)**	**9,609**	**(128)**	**756**	**221**	**20,926**
Consolidated net income attributable to Southern Company	—	—	—	—	—	**2,367**	—	—	—	**2,367**
Other comprehensive income (loss)	—	—	—	—	—	—	**(2)**	—	—	**(2)**
Stock issued	**6,571**	**(2,599)**	**33**	**223**	—	—	—	—	—	**256**
Stock-based compensation	—	—	—	**100**	—	—	—	—	—	**100**
Stock repurchased, at cost	—	—	—	—	**(115)**	—	—	—	—	**(115)**
Cash dividends of $2.1525 per share	—	—	—	—	—	**(1,959)**	—	—	—	**(1,959)**
Preference stock redemptions	—	—	—	—	—	—	—	**(150)**	—	**(150)**
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	**567**	**567**
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	**(18)**	**(18)**
Net income attributable to noncontrolling interests	—	—	—	—	—	—	—	—	**12**	**12**
Other	—	**(28)**	—	**4**	**(1)**	**(7)**	—	**3**	**(1)**	**(2)**
Balance at December 31, 2015	**915,073**	**(3,352)**	**$4,572**	**$ 6,282**	**$ (142)**	**$ 10,010**	**$ (130)**	**$ 609**	**$ 781**	**$ 21,982**

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

NOTES TO FINANCIAL STATEMENTS
Southern Company and Subsidiary Companies 2015 Annual Report

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NOTES (continued)
Southern Company and Subsidiary Companies 2015 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

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

The financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities where the Company has an equity investment but is not the primary beneficiary. Intercompany transactions have been eliminated in consolidation.

The traditional operating companies, Southern Power, and certain of their subsidiaries are subject to regulation by the FERC, and the traditional operating companies are also subject to regulation by their respective state PSCs. As such, each of 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 their respective commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

In June 2015, Georgia Power identified an error affecting the billing to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing from January 1, 2013 to June 30, 2015. In the second quarter 2015, Georgia Power recorded an out of period adjustment of approximately $75 million to decrease retail revenues, resulting in a decrease to net income of approximately $47 million . Georgia Power evaluated the effects of this error on the interim and annual periods that included the billing error, as well as the current period. Based on an analysis of qualitative and quantitative factors, Georgia Power determined the error was not material to any affected period and, therefore, an amendment of previously filed financial statements was not required.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers,* revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. Southern Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $202 million as of December 31, 2014. These debt issuance costs were previously presented within unamortized debt issuance expense. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of Southern Company. See Notes 6 and 10 for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), effective for fiscal years beginning after December 15, 2015. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of Southern Company. See Notes 2 and 10 for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from deferred income taxes, current of $506 million , with $488 million to non-current accumulated deferred income taxes and $18 million to other deferred charges, as well as $2 million from accrued income taxes to non-current accumulated deferred income taxes in Southern Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of Southern Company. See Note 5 for disclosures impacted by ASU 2015-17.

Regulatory Assets and Liabilities

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

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

	2015	2014	Note
	(in millions)		
Retiree benefit plans	$ 3,440	$ 3,469	(a,n)
Deferred income tax charges	1,514	1,458	(b)
Asset retirement obligations-asset	481	119	(b,n)
Other regulatory assets	299	275	(k)
Loss on reacquired debt	248	267	(c)
Fuel-hedging-asset	225	202	(d,n)
Kemper IGCC regulatory assets	216	148	(h)
Vacation pay	178	177	(f,n)
Deferred PPA charges	163	185	(e,n)
Under recovered regulatory clause revenues	142	157	(g)
Remaining net book value of retired assets	283	44	(o)
Environmental remediation-asset	78	64	(j,n)
Property damage reserves-asset	92	98	(i)
Nuclear outage	88	99	(g)
Other cost of removal obligations	(1,177)	(1,229)	(b)
Over recovered regulatory clause revenues	(261)	(48)	(g)
Deferred income tax credits	(187)	(192)	(b)
Property damage reserves-liability	(178)	(181)	(l)
Asset retirement obligations-liability	(45)	(130)	(b,n)
Other regulatory liabilities	(35)	(47)	(m)
Mirror CWIP	—	(271)	(h)
Total regulatory assets (liabilities), net	$ 5,564	$ 4,664	

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 15 years . See Note 2 for additional information.

(b) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years . Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities. At December 31, 2015 , other cost of removal obligations included $14 million that will be amortized over the twelve months ending December 31, 2016 in accordance with Georgia Power's 2013 ARP.

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

(d) Recorded over the life of the underlying hedged purchase contracts, which generally do not exceed five years . Upon final settlement, actual costs incurred are recovered through the energy cost recovery clause.

(e) Recovered over the life of the PPA for periods up to eight years .

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

(g) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs over periods not exceeding 10 years .

(h) For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(i) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs over periods generally not exceeding six years .

(j) Recovered through the environmental cost recovery clause when the remediation is performed.

(k) Comprised of numerous immaterial components including deferred income tax charges - Medicare subsidy, cancelled construction projects, building leases, closure of Plant Scholz ash pond, Plant Daniel Units 3 and 4 regulatory assets, property tax, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the appropriate state PSCs over periods generally not exceeding 15 years .

(l) Recovered as storm restoration and potential reliability-related expenses are incurred as approved by the appropriate state PSCs.

(m) Comprised of numerous immaterial components including retiree benefit plans, fuel-hedging gains, and other liabilities that are recorded and recovered or amortized as approved by the appropriate state PSCs generally over periods not exceeding 15 years .

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

(o) Amortized as approved by the appropriate state PSCs over periods not exceeding 11 years .

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

Power," "Retail Regulatory Matters – Georgia Power," "Retail Regulatory Matters – Gulf Power, "and "Integrated Coal Gasification Combined Cycle" for additional information.

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors.

Southern Company's electric utility subsidiaries have a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel.

Income and Other Taxes

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income. In accordance with regulatory requirements, deferred federal ITCs for the traditional operating companies are amortized over the average lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Under current tax law, certain projects at Southern Power are eligible for federal ITCs or cash grants. Southern Power has elected to receive ITCs. The credits are recorded as a deferred credit and are amortized to income tax expense over the life of the asset. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. In addition, certain projects are eligible for federal production tax credits (PTC), which are recorded to income tax expense based on production.

Federal ITCs and PTCs, as well as state ITCs and other state tax credits available to reduce income taxes payable, were not fully utilized in 2015 and will be carried forward and utilized in future years. In addition, Southern Company has subsidiaries with various state net operating loss (NOL) carryforwards, which could result in net state income tax benefits in the future, if utilized. See Note 5 to the financial statements for additional information.

Southern Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less 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.

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

	2015	2014
	(in millions)	
Generation	$ 41,648	$ 37,892
Transmission	10,544	9,884
Distribution	17,670	17,123
General	4,377	4,198
Plant acquisition adjustment	123	123
Utility plant in service	74,362	69,220
Information technology equipment and software	222	244
Communications equipment	418	439
Other	116	110
Other plant in service	756	793
Total plant in service	$ 75,118	$ 70,013

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 as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific state PSC orders. Alabama Power and Georgia Power defer and amortize nuclear refueling costs over the unit's operating cycle. The refueling cycles for Alabama Power's Plant Farley and Georgia Power's Plants Hatch and Vogtle Units 1 and 2 range from 18 to 24 months , depending on the unit.

Assets acquired under a capital lease are included in property, plant, and equipment and are further detailed in the table below:

	Asset Balances at December 31,	
	2015	2014
	(in millions)	
Office building	$ 61	$ 61
Nitrogen plant	83	83
Computer-related equipment	61	60
Gas pipeline	6	6
Less: Accumulated amortization	(59)	(49)
Balance, net of amortization	$ 152	$ 161

The amount of non-cash property additions recognized for the years ended December 31, 2015 , 2014 , and 2013 was $844 million , $528 million , and $411 million , respectively. These amounts are comprised of construction-related accounts payable outstanding at each year end. Also, the amount of non-cash property additions associated with capitalized leases for the years ended December 31, 2015 , 2014 , and 2013 was $13 million , $25 million , and $107 million , respectively.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.0% in 2015 , 3.1% in 2014 , and 3.3% in 2013 . Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC and the FERC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled $23.7 billion and $23.5 billion at December 31, 2015 and 2014 , respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Certain of Southern Power's generation assets are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. Cost, net of salvage value, of these assets is depreciated on an hours or starts units-of-production basis. Plant in service as of December 31, 2015 and 2014 that is depreciated on a units-of-production basis was approximately $485 million and $470 million , respectively.

Under the terms of Georgia Power's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP) and the 2013 ARP, Georgia Power amortized approximately $31 million in 2013 and $14 million in each of 2014 and 2015 of its remaining regulatory liability related to other cost of removal obligations.

See Note 3 under "Retail Regulatory Matters – Alabama Power – Cost of Removal Accounting Order " and "– Gulf Power – Retail Base Rate Case " for information regarding depreciation and amortization adjustments related to the other cost of removal regulatory liability by Alabama Power and Gulf Power, respectively.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from three to 25 years . Accumulated depreciation for other plant in service totaled $510 million and $533 million at December 31, 2015 and 2014 , respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) 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. Each traditional operating company has received accounting guidance from the various state PSCs allowing the continued accrual of other future retirement costs for long-lived assets that it 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 the decommissioning of the Southern Company system's nuclear facilities – Alabama Power's Plant Farley and Georgia Power's Plant Hatch and Plant Vogtle Units 1 and 2 – and facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA on April 17, 2015 (CCR Rule), principally ash ponds. In addition, the Southern Company system has retirement obligations related to various landfill sites, asbestos removal, mine reclamation, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the 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 Company will continue to recognize in the statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the various state PSCs, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

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

	2015	2014
	(in millions)	
Balance at beginning of year	**$ 2,201**	$ 2,018
Liabilities incurred	**662**	18
Liabilities settled	**(37)**	(17)
Accretion	**115**	102
Cash flow revisions	**818**	80
Balance at end of year	**$ 3,759**	$ 2,201

The increases in liabilities incurred and cash flow revisions in 2015 primarily relate to an increase in AROs associated with facilities impacted by the CCR Rule and Georgia Power's updated nuclear decommissioning study. The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2015 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 in place or by other methods. 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, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the traditional operating companies expect to continue to periodically update these estimates.

The cash flow revisions in 2014 are primarily related to Alabama Power's and SEGCO's AROs associated with asbestos at their steam generation facilities.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the IRS. While Alabama Power and Georgia Power are allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of Southern Company, Alabama Power, and Georgia Power. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

Southern Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds at Georgia Power participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2015 and 2014 , approximately $76 million and $51 million , respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $78 million and $52 million at December 31, 2015 and 2014 , respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2015 , investment securities in the Funds totaled $1.5 billion , consisting of equity securities of $817 million , debt securities of $654 million , and $38 million of other securities. At December 31, 2014 , investment securities in the Funds totaled $1.5 billion , consisting of equity securities of $886 million , debt securities of $638 million , and $19 million of other securities. These amounts include the investment securities pledged to creditors and collateral received and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $1.4 billion , $913 million , and $1.0 billion in 2015 , 2014 , and 2013 , respectively, all of which were reinvested. For 2015 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $11 million , which included $83 million related to unrealized losses on securities held in the Funds at December 31, 2015 . For 2014 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $98 million , which included $19 million related to unrealized gains and losses on securities held in the Funds at December 31, 2014 . For 2013 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $181 million , which included $119 million related to unrealized gains on securities held in the Funds at December 31, 2013 . While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

For Alabama Power, amounts previously recorded in internal reserves are being transferred into the Funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2015 and 2014 , the accumulated provisions for decommissioning were as follows:

	External Trust Funds		Internal Reserves		Total	
	2015	2014	**2015**	2014	**2015**	2014
			(in millions)			
Plant Farley	**$ 734**	$ 754	**$ 20**	$ 21	**$ 754**	$ 775
Plant Hatch	**487**	496	**—**	—	**487**	496
Plant Vogtle Units 1 and 2	**288**	293	**—**	—	**288**	293

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning as of December 31, 2015 based on the most current studies, which were performed in 2013 for Alabama Power's Plant Farley and in 2015 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:			
Beginning year	2037	2034	2047
Completion year	2076	2075	2079
		(in millions)	
Site study costs:			
Radiated structures	$ 1,362	$ 678	$ 568
Spent fuel management	—	160	147
Non-radiated structures	80	64	89
Total site study costs	$ 1,442	$ 902	$ 804

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study, and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved Georgia Power's annual decommissioning cost through 2016 for ratemaking of $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Georgia Power expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and 2.4% for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0% and 4.4% for Alabama Power and Georgia Power, respectively.

Amounts previously contributed to the Funds for Plant Farley are currently projected to be adequate to meet the decommissioning obligations. Alabama Power will continue to provide site-specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with NRC and other applicable requirements.

Allowance for Funds Used During Construction and Interest Capitalized

In accordance with regulatory treatment, the traditional operating companies record AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, 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 calculating taxable income. Interest related to the construction of new facilities not included in the traditional operating companies' regulated rates is capitalized in accordance with standard interest capitalization requirements. AFUDC and interest capitalized, net of income taxes were 12.8% , 16.0% , and 15.0% of net income for 2015 , 2014 , and 2013 , respectively.

Cash payments for interest totaled $809 million , $732 million , and $759 million in 2015 , 2014 , and 2013 , respectively, net of amounts capitalized of $124 million , $111 million , and $92 million , respectively.

Impairment of Long-Lived Assets and Intangibles

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

Storm Damage Reserves

Each traditional operating company maintains a reserve to cover or is allowed to defer and recover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In accordance with their respective state PSC orders, the traditional operating companies accrued $40 million , $40 million , and $28 million in 2015 , 2014 , and 2013 , respectively. Alabama Power, Gulf Power, and Mississippi Power also have authority based on orders from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2015 , 2014 , and 2013 , there were no such additional accruals. See Note 3 under "Retail Regulatory Matters – Alabama Power – Rate NDR" and "Retail Regulatory Matters – Georgia Power – Storm Damage Recovery" for additional information regarding Alabama Power's NDR and Georgia Power's deferred storm costs, respectively.

Leveraged Leases

Southern Company has several leveraged lease agreements, with original terms ranging up to 45 years , which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. The Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows.

Southern Company's net investment in domestic and international leveraged leases consists of the following at December 31:

	2015	2014
	(in millions)	
Net rentals receivable	**$ 1,487**	$ 1,495
Unearned income	**(732)**	(752)
Investment in leveraged leases	**755**	743
Deferred taxes from leveraged leases	**(303)**	(299)
Net investment in leveraged leases	**$ 452**	$ 444

A summary of the components of income from the leveraged leases follows:

	2015	2014	2013
		(in millions)	
Pretax leveraged lease income (loss)	**$ 20**	$ 24	$ (5)
Income tax expense	**(7)**	(9)	2
Net leveraged lease income (loss)	**$ 13**	$ 15	$ (3)

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the traditional operating companies through fuel cost recovery rates approved by each state PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

Southern Company and its subsidiaries use 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 10 for additional information regarding fair value. Substantially all of the Southern Company system's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional operating companies' fuel-hedging programs result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts 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 income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2015 , the amount included in accounts payable in the balance sheets that the Company has recognized for the obligation to return cash collateral arising from derivative instruments was immaterial.

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

Comprehensive Income

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

Accumulated OCI (loss) balances, net of tax effects, were as follows:

	Qualifying Hedges	Marketable Securities	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
		(in millions)		
Balance at December 31, 2014	$ (41)	$ —	$ (87)	$ (128)
Current period change	(7)	—	5	(2)
Balance at December 31, 2015	**$ (48)**	**$ —**	**$ (82)**	**$ (130)**

2. RETIREMENT BENEFITS

Southern Company has a defined benefit, trusted, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2016 . Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2016 , other postretirement trust contributions are expected to total approximately $14 million .

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:	2015	2014	2013
Pension plans			
Discount rate – interest costs	**4.17%**	5.02%	4.26%
Discount rate – service costs	**4.48**	5.02	4.26
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**3.59**	3.59	3.59
Other postretirement benefit plans			
Discount rate – interest costs	**4.04%**	4.85%	4.05%
Discount rate – service costs	**4.39**	4.85	4.05
Expected long-term return on plan assets	**6.97**	7.15	7.13
Annual salary increase	**3.59**	3.59	3.59

Assumptions used to determine benefit obligations:	2015	2014
Pension plans		
Discount rate	**4.67%**	4.17%
Annual salary increase	**4.46**	3.59
Other postretirement benefit plans		
Discount rate	**4.51%**	4.04%
Annual salary increase	**4.46**	3.59

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

For purposes of its December 31, 2015 measurement date, the Company adopted new mortality tables for its pension and other postretirement benefit plans, which reflect decreased life expectancies in the U.S. The adoption of new mortality tables reduced the projected benefit obligations for the Company's pension and other postretirement benefit plans by approximately $191 million and $35 million , respectively.

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, 2015 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2024
Post-65 medical	5.50	4.50	2024
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, 2015 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 119	$ (102)
Service and interest costs	4	(4)

Pension Plans

The total accumulated benefit obligation for the pension plans was $9.6 billion at December 31, 2015 and $10.0 billion at December 31, 2014 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 10,909**	$ 8,863
Service cost	**257**	213
Interest cost	**445**	435
Benefits paid	**(487)**	(382)
Actuarial loss (gain)	**(582)**	1,780
Balance at end of year	**10,542**	10,909
Change in plan assets		
Fair value of plan assets at beginning of year	**9,690**	8,733
Actual return (loss) on plan assets	**(14)**	797
Employer contributions	**45**	542
Benefits paid	**(487)**	(382)
Fair value of plan assets at end of year	**9,234**	9,690
Accrued liability	**$ (1,308)**	$ (1,219)

At December 31, 2015 , the projected benefit obligations for the qualified and non-qualified pension plans were $10.0 billion and $582 million , respectively. All pension plan assets are related to the qualified pension plan.

NOTES (continued)
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Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's pension plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 2,998**	$ 3,073
Other current liabilities	**(46)**	(42)
Employee benefit obligations	**(1,262)**	(1,177)
Accumulated OCI	**125**	134

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2015 and 2014 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 2016 .

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2015:		
Accumulated OCI	**$ 3**	**$ 122**
Regulatory assets	**27**	**2,971**
Total	**$ 30**	**$ 3,093**
Balance at December 31, 2014:		
Accumulated OCI	$ 4	$ 130
Regulatory assets	51	3,022
Total	$ 55	$ 3,152
Estimated amortization in net periodic pension cost in 2016:		
Accumulated OCI	**$ 1**	**$ 6**
Regulatory assets	**13**	**145**
Total	**$ 14**	**$ 151**

NOTES (continued)
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The components of OCI and the changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2015 and 2014 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2013	$ 64	$ 1,651
Net gain	75	1,552
Change in prior service costs	—	1
Reclassification adjustments:		
Amortization of prior service costs	(1)	(25)
Amortization of net gain	(4)	(106)
Total reclassification adjustments	(5)	(131)
Total change	70	1,422
Balance at December 31, 2014	$ 134	$ 3,073
Net loss	**1**	**155**
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	**(24)**
Amortization of net gain	**(9)**	**(206)**
Total reclassification adjustments	**(10)**	**(230)**
Total change	**(9)**	**(75)**
Balance at December 31, 2015	**$ 125**	**$ 2,998**

Components of net periodic pension cost were as follows:

	2015	2014	2013
		(in millions)	
Service cost	**$ 257**	$ 213	$ 232
Interest cost	**445**	435	389
Expected return on plan assets	**(724)**	(645)	(603)
Recognized net loss	**215**	110	200
Net amortization	**25**	26	27
Net periodic pension cost	**$ 218**	$ 139	$ 245

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.

NOTES (continued)
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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, 2015 , estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2016	$ 450
2017	478
2018	501
2019	527
2020	554
2021 to 2025	3,141

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,986**	$ 1,682
Service cost	**23**	21
Interest cost	**78**	79
Benefits paid	**(102)**	(102)
Actuarial loss (gain)	**(38)**	300
Plan amendments	**34**	(2)
Retiree drug subsidy	**8**	8
Balance at end of year	**1,989**	1,986
Change in plan assets		
Fair value of plan assets at beginning of year	**900**	901
Actual return (loss) on plan assets	**(12)**	54
Employer contributions	**39**	39
Benefits paid	**(94)**	(94)
Fair value of plan assets at end of year	**833**	900
Accrued liability	**$ (1,156)**	$ (1,086)

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's other postretirement benefit plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 433**	$ 387
Other current liabilities	**(4)**	(4)
Employee benefit obligations	**(1,152)**	(1,082)
Other regulatory liabilities, deferred	**(22)**	(21)
Accumulated OCI	**8**	8

NOTES (continued)
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Presented below are the amounts included in accumulated OCI and net regulatory assets (liabilities) at December 31, 2015 and 2014 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2016 .

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2015:		
Accumulated OCI	**$ —**	**$ 8**
Net regulatory assets	**32**	**379**
Total	**$ 32**	**$ 387**
Balance at December 31, 2014:		
Accumulated OCI	$ —	$ 8
Net regulatory assets	2	364
Total	$ 2	$ 372
Estimated amortization as net periodic postretirement benefit cost in 2016:		
Net regulatory assets	**$ 6**	**$ 14**

The components of OCI, along with the changes in the balance of net regulatory assets (liabilities), related to the other postretirement benefit plans for the plan years ended December 31, 2015 and 2014 are presented in the following table:

	Accumulated OCI	Net Regulatory Assets (Liabilities)
	(in millions)	
Balance at December 31, 2013	$ 1	$ 73
Net gain	7	301
Change in prior service costs	—	(2)
Reclassification adjustments:		
Amortization of prior service costs	—	(4)
Amortization of net gain	—	(2)
Total reclassification adjustments	—	(6)
Total change	7	293
Balance at December 31, 2014	$ 8	$ 366
Net gain	—	**33**
Change in prior service costs	—	**33**
Reclassification adjustments:		
Amortization of prior service costs	—	**(4)**
Amortization of net gain	—	**(17)**
Total reclassification adjustments	—	**(21)**
Total change	—	**45**
Balance at December 31, 2015	**$ 8**	**$ 411**

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

	2015	2014	2013
		(in millions)	
Service cost	$ 23	$ 21	$ 24
Interest cost	78	79	74
Expected return on plan assets	(58)	(59)	(56)
Net amortization	21	6	21
Net periodic postretirement benefit cost	$ 64	$ 47	$ 63

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)	
2016	$ 123	$ (9)	$ 114
2017	128	(10)	118
2018	133	(11)	122
2019	137	(12)	125
2020	139	(12)	127
2021 to 2025	711	(65)	646

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.

NOTES (continued)
Southern Company and Subsidiary Companies 2015 Annual Report

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2015 and 2014 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2015**	2014
Pension plan assets:			
Domestic equity	26%	**30%**	30%
International equity	25	**23**	23
Fixed income	23	**23**	27
Special situations	3	**2**	1
Real estate investments	14	**16**	14
Private equity	9	**6**	5
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	42%	**38%**	41%
International equity	21	**23**	23
Domestic fixed income	24	**26**	26
Global fixed income	4	**4**	3
Special situations	1	**1**	—
Real estate investments	5	**6**	5
Private equity	3	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns 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.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***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, 2015 and 2014 . 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.
- ***TOLI.*** Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

NOTES (continued)
Southern Company and Subsidiary Companies 2015 Annual Report

The fair values of pension plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 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*	$ 1,632	$ 681	$ —	$ —	$ 2,313
International equity*	1,190	990	—	—	2,180
Fixed income:					
U.S. Treasury, government, and agency bonds	—	454	—	—	454
Mortgage- and asset-backed securities	—	199	—	—	199
Corporate bonds	—	1,140	—	—	1,140
Pooled funds	—	500	—	—	500
Cash equivalents and other	—	145	—	—	145
Real estate investments	299	—	—	1,218	1,517
Private equity	—	—	—	635	635
Total	$ 3,121	$ 4,109	$ —	$ 1,853	$ 9,083
Liabilities:					
Derivatives	$ (1)	$ —	$ —	$ —	$ (1)
Total	$ 3,120	$ 4,109	$ —	$ 1,853	$ 9,082

* 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.

NOTES (continued)
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As of December 31, 2014:	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*	$ 1,704	$ 704	$ —	$ —	$ 2,408
International equity*	1,070	986	—	—	2,056
Fixed income:					
U.S. Treasury, government, and agency bonds	—	699	—	—	699
Mortgage- and asset-backed securities	—	188	—	—	188
Corporate bonds	—	1,135	—	—	1,135
Pooled funds	—	514	—	—	514
Cash equivalents and other	3	660	—	—	663
Real estate investments	293	—	—	1,121	1,414
Private equity	—	—	—	570	570
Total	$ 3,070	$ 4,886	$ —	$ 1,691	$ 9,647
Liabilities:					
Derivatives	$ (2)	$ —	$ —	$ —	$ (2)
Total	$ 3,068	$ 4,886	$ —	$ 1,691	$ 9,645

* 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.

NOTES (continued)
Southern Company and Subsidiary Companies 2015 Annual Report

The fair values of other postretirement benefit plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

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*	$ 106	$ 52	$ —	$ —	$ 158
International equity*	40	64	—	—	104
Fixed income:					
U.S. Treasury, government, and agency bonds	—	22	—	—	22
Mortgage- and asset-backed securities	—	7	—	—	7
Corporate bonds	—	38	—	—	38
Pooled funds	—	42	—	—	42
Cash equivalents and other	11	9	—	—	20
Trust-owned life insurance	—	370	—	—	370
Real estate investments	11	—	—	41	52
Private equity	—	—	—	21	21
Total	$ 168	$ 604	$ —	$ 62	$ 834

* 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, 2014:	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*	$ 147	$ 56	$ —	$ —	$ 203
International equity*	36	67	—	—	103
Fixed income:					
U.S. Treasury, government, and agency bonds	—	29	—	—	29
Mortgage- and asset-backed securities	—	6	—	—	6
Corporate bonds	—	39	—	—	39
Pooled funds	—	41	—	—	41
Cash equivalents and other	9	27	—	—	36
Trust-owned life insurance	—	381	—	—	381
Real estate investments	11	—	—	37	48
Private equity	—	—	—	19	19
Total	$ 203	$ 646	$ —	$ 56	$ 905

* 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

Southern Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2015 , 2014 , and 2013 were $92 million , $87 million , and $84 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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 Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements.

AGL Resources Merger Litigation

AGL Resources and each member of the AGL Resources board of directors were named as defendants in four purported shareholder class action lawsuits filed in the United States District Court for the Northern District of Georgia in September and October 2015. These actions were filed on behalf of named plaintiffs and other AGL Resources shareholders challenging the Merger and seeking, among other things, preliminary and permanent injunctive relief enjoining the Merger, and, in certain circumstances, damages. Southern Company and Merger Sub were also named as defendants in two of these lawsuits. On October 23, 2015, the court consolidated the four lawsuits into a single action. On January 4, 2016, the parties filed a proposed stipulated order of dismissal, asking the court to dismiss the consolidated amended complaint without prejudice, which the court approved on January 5, 2016. See Note 12 under "Southern Company – Proposed Merger with AGL Resources" for additional information regarding the Merger.

Environmental Matters

Environmental Remediation

The Southern Company system 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 Southern Company system could incur substantial costs to clean up affected sites. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs.

Georgia Power's environmental remediation liability as of December 31, 2015 was $29 million . Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a site in Brunswick, Georgia on the CERCLA National Priorities List. The PRPs at the Brunswick site have completed a removal action as ordered by the EPA. Additional response actions at this site are anticipated. In September 2015, Georgia Power entered into an allocation agreement with another PRP, under which that PRP will be responsible (as between Georgia Power and that PRP) for paying and performing certain investigation, assessment, remediation, and other incidental activities at the Brunswick site. Assessment and potential cleanup of other sites are anticipated.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of Georgia Power's regulatory treatment for environmental remediation expenses, these matters are not expected to have a material impact on Southern Company's financial statements.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $46 million as of December 31, 2015 . These estimated costs primarily relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

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

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with Alabama Power and Georgia Power that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plants Hatch and Farley and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, Alabama Power and Georgia Power pursued and continue to pursue legal remedies against the U.S. government for its partial breach of contract.

In December 2014, the Court of Federal Claims entered a judgment in favor of Georgia Power and Alabama Power in their spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. On March 19, 2015, Georgia Power recovered approximately $18 million , based on its ownership interests, and Alabama Power recovered approximately $26 million . In March 2015, Georgia Power credited the award to accounts where the original costs were charged and reduced rate base, fuel, and cost of service for the benefit of customers. In November 2015, Alabama Power applied the retail-related proceeds to offset the nuclear fuel expense under Rate ECR. See "Retail Regulatory Matters – Alabama Power – Nuclear Waste Fund Accounting Order" herein for additional information. In December 2015, Alabama Power credited the wholesale-related proceeds to each wholesale customer.

In March 2014, Alabama Power and Georgia Power filed additional lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of

December 31, 2015 for any potential recoveries from the additional lawsuits. The final outcome of these matters cannot be determined at this time; however, no material impact on Southern Company's net income is expected.

On-site dry spent fuel storage facilities are operational at all three plants and can be expanded to accommodate spent fuel through the expected life of each plant.

FERC Matters

The traditional operating companies and Southern Power have 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 operating companies and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. The FERC directed the traditional operating companies 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 operating companies and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Alabama Power

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon Alabama Power's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Retail rates remain unchanged when the WCE ranges between 5.75% and 6.21% . Rate RSE adjustments for any two -year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0% . If Alabama Power's actual retail return is above the allowed WCE range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

In 2013, the Alabama PSC approved a revision to Rate RSE, effective for calendar year 2014. This revision established the WCE range of 5.75% to 6.21% with an adjusting point of 5.98% and provided eligibility for a performance-based adder of seven basis points, or 0.07% , to the WCE adjusting point if Alabama Power (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

The Rate RSE increase for 2015 was 3.49% or $181 million annually, and was effective January 1, 2015. On November 30, 2015, Alabama Power made its annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2016. Projected earnings were within the specified WCE range; therefore, retail rates under Rate RSE remained unchanged for 2016.

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 3, 2015, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2015 through March 31, 2016. No adjustment to Rate CNP PPA is expected in 2016. As of December 31, 2015 , Alabama Power had an under recovered certificated PPA balance of $99 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Rate CNP Environmental allowed for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, and other such mandates. On March 3, 2015, the Alabama PSC approved a modification to Rate CNP Environmental to include compliance costs for both environmental and non-environmental mandates. The recoverable non-environmental compliance costs result from laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. This modification to Rate CNP Environmental was effective March 20, 2015 with the revised rate now defined as Rate CNP Compliance. Alabama Power was limited to recover $50 million of non-environmental compliance costs for the year 2015. Additional non-environmental compliance costs were recovered through Rate RSE. Customer rates were not impacted by this order in 2015; therefore, the modification increased the under recovered position for Rate CNP Compliance during 2015. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital.

Rate CNP Compliance increased 1.5% , or $75 million annually, effective January 1, 2015. As of December 31, 2015, Alabama Power had an under recovered compliance clause balance of $43 million , which is included in under recovered regulatory clause revenues in the balance sheet.

Rate ECR

Alabama Power has established energy cost recovery rates under Alabama Power's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. Alabama Power, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on Southern Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. In December 2014, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2015 the Rate ECR factor of 2.681 cents per KWH.

On December 1, 2015, the Alabama PSC approved a decrease in Alabama Power’s Rate ECR factor from 2.681 to 2.030 cents per KWH, 6.7% , or $370 million annually, based upon projected billings, effective January 1, 2016. The approved decrease in the Rate ECR factor will have no significant effect on Southern Company's net income, but will decrease operating cash flows related to fuel cost recovery in 2016 when compared to 2015. The rate will return to 2.681 cents per KWH in 2017 and 5.910 cents per KWH in 2018, absent a further order from the Alabama PSC.

Alabama Power's over recovered fuel costs at December 31, 2015 totaled $238 million as compared to $47 million at December 31, 2014 . At December 31, 2015 , $238 million is included in other regulatory liabilities, current. The over recovered fuel costs at December 31, 2014 are included in deferred over recovered regulatory clause revenues. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery or return of fuel costs.

Rate NDR

Based on an order from the Alabama PSC, Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24 -month period. The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. Alabama Power has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million . Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

Environmental Accounting Order

Based on an order from the Alabama PSC, Alabama Power is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs, associated with site removal and closure associated with future unit retirements caused by environmental regulations. These costs are being amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance.

In April 2015, as part of its environmental compliance strategy, Alabama Power retired Plant Gorgas Units 6 and 7 (200 MWs). Additionally, in April 2015, Alabama Power ceased using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. In accordance with the joint stipulation entered in connection with a civil enforcement action by the EPA, Alabama Power retired Plant Barry Unit 3 (225 MWs) in August 2015 and it is no longer available for generation. Alabama Power expects to cease using coal at Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas by April 2016.

In accordance with this accounting order from the Alabama PSC, Alabama Power transferred the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized and recovered through Rate CNP Compliance over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on Southern Company's financial statements.

Nuclear Waste Fund Accounting Order

In 2013, the U.S. District Court for the District of Columbia ordered the DOE to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the DOE either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. The DOE formally set the fee to zero effective May 16, 2014.

In August 2014, the Alabama PSC issued an order to provide for the continued recovery from customers of amounts associated with the permanent disposal of nuclear waste from the operation of Plant Farley. In accordance with the order, effective May 16, 2014, Alabama Power was authorized to recover from customers an amount equal to the prior fee and to record the amounts in a regulatory liability account (approximately $14 million annually). On December 1, 2015, the Alabama PSC issued an order for Alabama Power to discontinue recording the amounts recovered from customers in a regulatory liability account and transfer amounts recorded in the regulatory liability to Rate ECR. On December 1, 2015, Alabama Power transferred $20 million from the regulatory liability to Rate ECR to offset fuel expense.

Cost of Removal Accounting Order

In accordance with an accounting order issued in November 2014 by the Alabama PSC, in December 2014, Alabama Power fully amortized the balance of $123 million in certain regulatory asset accounts and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset accounts fully amortized and terminated as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, which were approved by the Alabama PSC in 2012 and 2013, respectively. Approximately $95 million of non-nuclear outage costs and $28 million of compliance and pension costs were fully amortized in December 2014.

Georgia Power

Rate Plans

In 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among Georgia Power, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors.

In January 2014, in accordance with the 2013 ARP, Georgia Power increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million ; (2) Environmental Compliance Cost Recovery (ECCR) tariff by approximately $25 million ; (3) Demand-Side Management (DSM) tariffs by approximately $1 million ; and (4) Municipal Franchise Fee (MFF) tariff by approximately $4 million , for a total increase in base revenues of approximately $110 million .

On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved an increase to tariffs effective January 1, 2015 as follows: (1) traditional base tariff rates by approximately $107 million ; (2) ECCR tariff by approximately $23 million ; (3) DSM tariffs by approximately $3 million ; and (4) MFF tariff by approximately $3 million , for a total increase in base revenues of approximately $136 million .

On December 16, 2015, in accordance with the 2013 ARP, the Georgia PSC approved an increase to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million ; (2) ECCR tariff by approximately $75 million ; (3) DSM tariffs by approximately $3 million ; and (4) MFF tariff by approximately $13 million , for a total increase in base revenues of approximately $140 million .

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00% . Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, Georgia Power's retail ROE exceeded 12.00% , and Georgia Power will refund to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, Georgia Power's retail ROE was within the allowed retail ROE range.

Georgia Power is required to file a general base rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plan

To comply with the April 16, 2015 effective date of the MATS rule, Plant Branch Units 1, 3, and 4 (1,266 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) were retired and operations were discontinued at Plant Mitchell Unit 3 (155 MWs) by April 15, 2015, and Plant Kraft Units 1 through 4 (316 MWs) were retired on October 13, 2015. The switch to natural gas as the primary fuel was completed at Plant Yates Units 6 and 7 by June 2015 and at Plant Gaston Units 1 through 4 by December 2015.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years ending December 2022 and the amortization of the remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024.

On January 29, 2016, Georgia Power filed its triennial IRP (2016 IRP). The filing included a request to decertify Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs) upon approval of the 2016 IRP. The 2016 IRP also reflects that Georgia Power exercised its contractual option to sell its 33% ownership interest in the Intercession City unit (143 MWs total capacity) to Duke Energy Florida, Inc. See Note 4 for additional information.

In the 2016 IRP, Georgia Power requested reclassification of the remaining net book value of Plant Mitchell Unit 3, as of its retirement date, to a regulatory asset to be amortized over a period equal to the unit's remaining useful life. Georgia Power also requested that the Georgia PSC approve the deferral of the cost associated with materials and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a period deemed appropriate by the Georgia PSC.

The decertification and retirement of these units are not expected to have a material impact on Southern Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's orders in the 2016 IRP and next general base rate case.

Additionally, the 2016 IRP included a Renewable Energy Development Initiative requesting to procure up to 525 MWs of renewable resources utilizing market-based prices established through a competitive bidding process to expand Georgia Power's existing renewable initiatives, including the Advanced Solar Initiative.

A decision from the Georgia PSC on the 2016 IRP is expected in the third quarter 2016. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved a reduction in Georgia Power's total annual billings of approximately $567 million effective June 1, 2012, with an additional $122 million reduction effective January 1, 2013 through June 1, 2014. Under an Interim Fuel Rider, Georgia Power continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million . Georgia Power's fuel cost recovery includes costs associated with a natural gas hedging program, as approved by the Georgia PSC in 2015, allowing it to use an array of derivative instruments within a 48 -month time horizon effective January 1, 2016. See Note 11 under "Energy-Related Derivatives" for additional information. On December 15, 2015, the Georgia PSC approved Georgia Power's request to lower annual billings by approximately $350 million effective January 1, 2016.

Georgia Power's over recovered fuel balance totaled approximately $116 million at December 31, 2015 and is included in current liabilities and other deferred liabilities. At December 31, 2014 , Georgia Power's under recovered fuel balance totaled approximately $199 million and was included in current assets and other deferred charges and assets.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow.

Storm Damage Recovery

Georgia Power defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Beginning January 1, 2014, Georgia Power is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. As of December 31, 2015 and December 31, 2014 , the balance in the regulatory asset related to storm damage was $92 million and $98 million , respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $62 million and $68 million included in other regulatory assets, deferred, respectively. Georgia Power expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs. As a result of the regulatory treatment, costs related to storms are generally not expected to have a material impact on Southern Company's financial statements.

Nuclear Construction

In 2008, Georgia Power, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (Westinghouse and Stone & Webster, Inc., collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not occurred), with maximum additional capital costs under this provision attributable to Georgia Power (based on Georgia Power's ownership interest) of approximately $114 million . Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share is 45.7% .

On December 31, 2015, Westinghouse acquired Stone & Webster, Inc. from CB&I (Acquisition). In connection with the Acquisition, Stone & Webster, Inc. changed its name to WECTEC Global Project Services Inc. (WECTEC). Certain obligations of Westinghouse and Stone & Webster, Inc. have been guaranteed by Toshiba Corporation, Westinghouse's parent company, and CB&I's The Shaw Group Inc., respectively. Subject to the consent of the DOE, in connection with the Acquisition and pursuant to the settlement agreement described below, the guarantee of The Shaw Group Inc. will be terminated. The guarantee of Toshiba Corporation remains in place. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement. Additionally, on January 13, 2016, as a result of recent credit rating downgrades of Toshiba Corporation, Westinghouse provided the Vogtle Owners with letters of credit in an aggregate amount of $900 million in accordance with, and subject to adjustment under, the terms of the Vogtle 3 and 4 Agreement.

The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events.

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges may arise as construction proceeds.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved an initial NCCR tariff of approximately $223 million effective January 1, 2011, as well as increases to the NCCR tariff of approximately $35 million , $50 million , $60 million , $27 million , and $19 million effective January 1, 2012, 2013, 2014, 2015, and 2016, respectively.

Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected construction capital costs to be borne by Georgia Power increase by 5% above the certified cost or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. In February 2013, Georgia Power requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 (from April 2016) and the fourth quarter 2018 (from April 2017) for Plant Vogtle Units 3 and 4, respectively. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between Georgia Power and the Georgia PSC Staff (Staff) to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and Georgia Power.

On April 15, 2015, the Georgia PSC issued a procedural order in connection with the twelfth VCM report, which included a requested amendment (Requested Amendment) to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 (second quarter of 2019 and second quarter of 2020, respectively) as well as additional estimated Vogtle Owner's costs, of approximately $10 million per month, including property taxes, oversight costs, compliance costs, and other operational readiness costs to include the estimated Vogtle Owner's costs associated with the proposed 18 - month Contractor delay and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion . Pursuant to the Georgia PSC's procedural order, the Georgia PSC deemed the Requested Amendment unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation. The Georgia PSC recognized that the certified cost and the 2013 Stipulation do not constitute a cost recovery cap. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by Georgia Power in excess of the certified amount will be included in rate base, provided Georgia Power shows the costs to be reasonable and prudent. Financing costs up to the certified amount will be collected through the NCCR tariff until the units are placed in service and contemplated in a general base rate case, while financing costs on any construction-related costs in excess of the $4.4 billion certified amount are expected to be recovered through AFUDC.

In 2012, the Vogtle Owners and the Contractor commenced litigation regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The Contractor also asserted that it was entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. In May 2014, the Contractor filed an amended claim alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. In June 2015, the Contractor updated its estimated damages to an aggregate (based on Georgia Power's ownership interest) of approximately $714 million (in 2015 dollars). The case was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation).

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including the Vogtle Construction Litigation. Effective December 31, 2015, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to match the current estimated in-service dates of June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will now commence from the current estimated nuclear fuel loading date for each unit, which is December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4, rather than the original guaranteed substantial completion dates under the Vogtle 3 and 4 Agreement; and (v) provide that Georgia Power, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million , of which approximately $120 million has been paid previously under the dispute resolution procedures of the Vogtle 3 and 4 Agreement. Further, subsequent to December 31, 2015, Georgia Power paid approximately $121 million under the terms of the Contractor Settlement Agreement. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs were reflected in Georgia Power's previously disclosed in-service cost estimate. Further, as part of the settlement and in connection with the Acquisition: (i) Westinghouse has engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor; and (ii) the Vogtle Owners, CB&I, and The Shaw Group Inc. have entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On January 21, 2016, Georgia Power submitted the Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement to the Georgia PSC for its review. On February 2, 2016, the Georgia PSC ordered Georgia Power to file supplemental information by April 5, 2016 in support of the Contractor Settlement Agreement and Georgia Power's position that all construction costs to date have been prudently incurred and that the current estimated in-service capital cost and schedule are reasonable. Following Georgia Power's filing under the order, the Staff will conduct a review of all costs incurred related to Plant Vogtle Units 3 and 4, the schedule for completion of Plant Vogtle Units 3 and 4, and the Contractor Settlement Agreement and the Staff is authorized to engage in related settlement discussions with Georgia Power and any intervenors.

The order provides that the Staff is required to report to the Georgia PSC by October 5, 2016 with respect to the status of its review and any settlement-related negotiations. If a settlement with the Staff is reached with respect to costs of Plant Vogtle Units 3 and 4, the Georgia PSC will then conduct a hearing to consider whether to approve that settlement. If a settlement with the Staff is not reached, the Georgia PSC will determine how to proceed, including (i) modifying the 2013 Stipulation, (ii) directing Georgia Power to file a request for an amendment to the certificate for Plant Vogtle Units 3 and 4, (iii) issuing a scheduling order to address remaining disputed issues, or (iv) taking any other option within its authority.

The Georgia PSC has approved thirteen VCM reports covering the periods through June 30, 2015, including construction capital costs incurred, which through that date totaled $3.1 billion . On February 26, 2016, Georgia Power filed its fourteenth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2015. The fourteenth VCM report does not include a requested amendment to the certified cost of Plant Vogtle Units 3 and 4. Georgia Power is requesting approval of $160 million of construction capital costs incurred during that period. Georgia Power anticipates to incur average financing costs of approximately $27 million per month from January 2016 until Plant Vogtle Units 3 and 4 are placed in service. The updated in-service capital cost forecast is $5.44 billion and includes costs related to the Contractor Settlement Agreement. Estimated financing costs during the construction period total approximately $2.4 billion . Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.6 billion as of December 31, 2015.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance issues may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

As construction continues, the risk remains that challenges with Contractor performance including fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Future claims by the Contractor or Georgia Power (on behalf of the Vogtle Owners) could arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement and, under the enhanced dispute resolution procedures, may be resolved through litigation after the completion of nuclear fuel load for both units.

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

Gulf Power

Retail Base Rate Case

In 2013, the Florida PSC voted to approve a settlement agreement among Gulf Power and all of the intervenors to Gulf Power's retail base rate case (Gulf Power Settlement Agreement). Under the terms of the Gulf Power Settlement Agreement, Gulf Power (1) increased base rates approximately $35 million annually effective January 2014 and subsequently increased base rates approximately $20 million annually effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) is accruing a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until Gulf Power's next base rate adjustment date or January 1, 2017, whichever comes first.

The Gulf Power Settlement Agreement also includes a self-executing adjustment mechanism that will increase the authorized retail ROE midpoint and range by 25 basis points in the event the 30 -year treasury yield rate increases by an average of at least 75 basis points above 3.7947% for a consecutive six -month period.

The Gulf Power Settlement Agreement also provides that Gulf Power may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in Gulf Power's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. For 2015 and 2014, Gulf Power recognized reductions in depreciation expense of $20.1 million and $8.4 million , respectively.

Pursuant to the Gulf Power Settlement Agreement, Gulf Power may not request an increase in its retail base rates to be effective until after June 2017, unless Gulf Power's actual retail ROE falls below the authorized ROE range.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of Mississippi Power's Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power 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, Mississippi Power constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC 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 grants awarded to the Kemper IGCC project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the 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. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service using natural gas in August 2014 and currently expects to place the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, in service during the third quarter 2016.

Recovery of the costs subject to the cost cap and 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 Mississippi Power 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) remains subject to review and approval by the Mississippi PSC. Mississippi Power's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision), and actual costs incurred as of December 31, 2015 , are as follows:

NOTES (continued)
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Cost Category	2010 Project Estimate (f)	Current Cost Estimate (a)	**Actual Costs**
		(in billions)	
Plant Subject to Cost Cap (b)(g)	$ 2.40	$ 5.29	**$ 4.83**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC (c)	0.17	0.69	**0.59**
Combined Cycle and Related Assets Placed in Service – Incremental (d)(g)	—	0.01	**0.01**
General Exceptions	0.05	0.10	**0.09**
Deferred Costs (e)(g)	—	0.20	**0.17**
Total Kemper IGCC	$ 2.97	$ 6.63	**$ 6.03**

(a) Amounts in the Current Cost Estimate reflect estimated costs through August 31, 2016.

(b) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , net of the DOE Grants and excluding the Cost Cap Exceptions. 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. The Current Cost Estimate and the Actual Costs reflect 100% of the costs of the Kemper IGCC. See note (g) for additional information.

(c) Mississippi Power's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs." The current estimate reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information.

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

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

(g) Beginning in the third quarter 2015, certain costs, including debt carrying costs (associated with assets placed in service and other non-CWIP accounts), that previously were deferred as regulatory assets are now being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2015 .

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2015 , $3.47 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.41 billion), $2 million in other property and investments, $69 million in fossil fuel stock, $45 million in materials and supplies, $21 million in other regulatory assets, current, $195 million in other regulatory assets, deferred, and $11 million in other deferred charges and assets in the balance sheet.

Mississippi Power 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 DOE Grants and excluding the Cost Cap Exceptions. Southern Company recorded pre-tax charges to income for revisions to the cost estimate above the cost cap of $365 million ($226 million after tax), $868 million ($536 million after tax), and $1.2 billion ($729 million after tax) in 2015, 2014, and 2013, respectively. The increases to the cost estimate in 2015 primarily reflect costs for the extension of the Kemper IGCC's projected in-service date through August 31, 2016, increased efforts related to scope modifications, additional labor costs in support of start-up and operational readiness activities, and system repairs and modifications after startup testing and commissioning activities identified necessary remediation of equipment installation, fabrication, and design issues, including the refractory lining inside the gasifiers; the lignite feed and dryer systems; and the syngas cooler vessels. Any extension of the in-service date beyond August 31, 2016 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 August 31, 2016 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 $13 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 $2 million per month. For additional information, see "2015 Rate Case" herein.

Mississippi Power's analysis of the time needed to complete the start-up and commissioning activities for the Kemper IGCC will continue until the remaining Kemper IGCC assets are placed in service. Further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, 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 for this first-of-a-kind technology (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). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

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

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both Mississippi Power's recovery of financing costs during the course of construction of the Kemper IGCC and Mississippi Power's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's petition for the CPCN. Mississippi Power expects the Mississippi PSC to apply operational parameters in connection with 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 Mississippi Power incurs additional costs to satisfy such parameters, there could be a material adverse impact on the financial statements.

2013 MPSC Rate Order

In January 2013, Mississippi Power 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, Mississippi Power 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.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, Mississippi Power continues to record AFUDC on the Kemper IGCC. Mississippi Power will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts.

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order. 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 discussed below.

2015 Rate Case

As a result of the 2015 Court decision, on July 10, 2015, Mississippi Power filed a supplemental filing including a request for interim rates (Supplemental Notice) with the Mississippi PSC which presented an alternative rate proposal (In-Service Asset Proposal) for consideration by the Mississippi PSC. The In-Service Asset Proposal was based upon the test period of June 2015 to May 2016, was designed to recover Mississippi Power'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, and was designed to collect approximately $159 million annually. On August 13, 2015, the Mississippi PSC approved the implementation of interim rates that became effective with the first billing cycle in September, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order) adopting in full a stipulation (the 2015 Stipulation) entered into between Mississippi Power and the MPUS regarding the In-Service Asset Proposal. Consistent with the 2015 Stipulation, the In-Service Asset Rate Order provides for retail rate recovery of an annual revenue requirement of approximately $126 million , based on Mississippi Power'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 during the test period. The In-Service Asset Rate Order also includes a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excludes the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA. See "Termination of Proposed Sale of Undivided Interest to SMEPA" herein for additional information.

With implementation of the new rate on December 17, 2015, the interim rates were terminated and Mississippi Power recorded a customer refund of approximately $11 million in December 2015 for the difference between the interim rates collected and the permanent rates. The refund is required to be completed by March 16, 2016.

Pursuant to the In-Service Asset Rate Order, Mississippi Power is required to file a subsequent rate request within 18 months . As part of the filing, Mississippi Power expects to request recovery of certain costs that the Mississippi PSC had excluded from the revenue requirement calculation.

On February 25, 2016, Greenleaf CO2 Solutions, LLC filed a notice of appeal of the In-Service Asset Rate Order with the Court. Mississippi Power believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on Southern Company's results of operations. The ultimate outcome of this matter cannot be determined at this time.

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. Mississippi Power expects 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 Mississippi Power's ability to utilize alternate financing through securitization or the February 2013 legislation.

Mississippi Power expects to seek additional rate relief to address recovery of the remaining Kemper IGCC assets. In addition to current estimated costs at December 31, 2015 of $6.63 billion , Mississippi Power anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Mississippi Power expects the Kemper IGCC to qualify for additional DOE grants included in the recently passed Consolidated Appropriations Act of 2015, which are expected to be used to reduce future rate impacts for customers. The ultimate outcome of this matter cannot be determined at this time.

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 Mississippi Power 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, Mississippi Power requested confirmation by the Mississippi PSC of Mississippi Power'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, Mississippi Power 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, in connection with the implementation of interim rates, Mississippi Power began expensing certain ongoing project costs and certain 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. As of December 31, 2015 , the balance associated with these regulatory assets was $120 million . Other regulatory assets associated with the remainder of the Kemper IGCC totaled $96 million as of December 31, 2015. The amortization period for these assets is expected to be determined by the Mississippi PSC in future rate proceedings following completion of construction and start-up of the Kemper IGCC and related prudence reviews.

See "2013 MPSC Rate Order" herein for information related to the July 7, 2015 Mississippi PSC order terminating the Mirror CWIP rate and requiring refund of collections under Mirror CWIP.

The In-Service Asset Rate Order requires Mississippi Power 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. As of December 31, 2015, Mississippi Power recorded a related regulatory liability of approximately $2 million . See "2015 Rate Case" herein for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, Mississippi Power 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 Mississippi Power has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, Mississippi Power currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, Mississippi Power has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. Mississippi Power has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide Denbury and Treetop with termination rights as Mississippi Power has not satisfied its contractual obligation to deliver captured CO_2 by May 11, 2015. Since May 11, 2015, Mississippi Power has been engaged in ongoing discussions with its off-takers regarding the status of the CO_2 delivery schedule as well as other issues related to the CO_2 agreements. As a result of discussions with Treetop, on August 3, 2015, Mississippi Power agreed to amend certain provisions of their agreement that do not affect pricing or minimum purchase quantities. Potential requirements imposed on CO_2 off-takers under the Clean Power Plan (if ultimately enacted in its current form, pending resolution of litigation) and the potential adverse financial impact of low oil prices on the off-takers increase the risk that the CO_2 contracts may be terminated or materially modified. Any termination or material modification of these agreements is not expected to have a material impact on Southern Company's revenues. Additionally, if the contracts remain in place, sustained oil price reductions could result in significantly lower revenues than Mississippi Power forecasted to be available to offset customer rate impacts.

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

Termination of Proposed Sale of Undivided Interest to SMEPA

In 2010 and as amended in 2012, Mississippi Power and SMEPA entered into an agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC. On May 20, 2015, SMEPA notified Mississippi Power that it was terminating the agreement. Mississippi Power had previously received a total of $275 million of deposits from SMEPA that were returned to SMEPA, with interest of approximately $26 million , on June 3, 2015, as a result of the termination by Southern Company, pursuant to its guarantee obligation. Subsequently, Mississippi Power issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures December 1, 2017.

The In-Service Asset Proposal and the related rates approved by the Mississippi PSC excluded any costs associated with the 15% undivided interest. Mississippi Power continues to evaluate its alternatives with respect to its investment and the related costs associated with the 15% undivided interest.

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years . The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 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 50% bonus depreciation is expected to result in approximately $3 million of positive cash flows related to the combined cycle and associated common facilities portion of the Kemper IGCC for the 2015 tax year and approximately $360 million for the 2016 tax year, which may not all be realized in 2016 due to a projected NOL on the

Company's 2016 income tax return, and is dependent upon placing the remainder of the Kemper IGCC in service in 2016. See "Kemper IGCC Schedule and Cost Estimate" herein for additional information. The ultimate outcome of this matter cannot be determined at this time.

Investment Tax Credits

The IRS allocated $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power 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 April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. As a result of the schedule extension for the Kemper IGCC, the Phase II tax credits have been recaptured.

Section 174 Research and Experimental Deduction

Southern Company reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations for 2013, 2014, and 2015. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures. Due to the uncertainty related to this tax position, Southern Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $423 million as of December 31, 2015 . See "Bonus Depreciation" herein and Note 5 under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in Units 1 and 2 at Plant Miller and related facilities jointly with PowerSouth Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, the City of Dalton, Georgia, Florida Power & Light Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities and with Duke Energy Florida, Inc. for a combustion turbine unit at Intercession City, Florida. Subsequent to December 31, 2015, Georgia Power exercised its contractual option to sell its ownership interest to Duke Energy Florida, Inc. contingent on regulatory approvals. Southern Power owns an undivided interest in Plant Stanton Unit A and related facilities jointly with the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency.

At December 31, 2015 , Alabama Power's, Georgia Power's, and Southern Power's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Percent Ownership	Plant in Service	Accumulated Depreciation	CWIP
			(in millions)	
Plant Vogtle (nuclear) Units 1 and 2	45.7%	$ 3,503	$ 2,084	$ 63
Plant Hatch (nuclear)	50.1	1,230	568	90
Plant Miller (coal) Units 1 and 2	91.8	1,518	587	63
Plant Scherer (coal) Units 1 and 2	8.4	260	86	1
Plant Wansley (coal)	53.5	915	290	13
Rocky Mountain (pumped storage)	25.4	181	125	—
Intercession City (combustion turbine)	33.3	13	4	—
Plant Stanton (combined cycle) Unit A	65.0	157	53	—

Georgia Power also owns 45.7% of Plant Vogtle Units 3 and 4 that are currently under construction. See Note 3 under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information.

Alabama Power and Georgia Power have contracted to operate and maintain their jointly-owned facilities, except for Rocky Mountain and Intercession City, as agents for their respective co-owners. Southern Power has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton Unit A. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income and each company is responsible for providing its own financing.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined or unitary. 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:

	2015	2014	2013
		(in millions)	
Federal —			
Current	**$ (177)**	$ 175	$ 363
Deferred	**1,266**	695	386
	1,089	870	749
State —			
Current	**(33)**	93	(10)
Deferred	**138**	14	110
	105	107	100
Total	**$ 1,194**	$ 977	$ 849

Net cash payments (refunds) for income taxes in 2015 , 2014 , and 2013 were $(9) million , $272 million , and $139 million , respectively.

NOTES (continued)
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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:

	2015	2014
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 12,767**	$ 11,125
Property basis differences	**1,543**	1,332
Leveraged lease basis differences	**308**	299
Employee benefit obligations	**579**	613
Premium on reacquired debt	**95**	103
Regulatory assets associated with employee benefit obligations	**1,378**	1,390
Regulatory assets associated with AROs	**1,422**	871
Other	**586**	523
Total	**18,678**	16,256
Deferred tax assets —		
Federal effect of state deferred taxes	**479**	430
Employee benefit obligations	**1,720**	1,675
Over recovered fuel clause	**104**	—
Other property basis differences	**695**	453
Deferred costs	**83**	86
ITC carryforward	**742**	480
Unbilled revenue	**111**	67
Other comprehensive losses	**85**	89
AROs	**1,422**	871
Estimated Loss on Kemper IGCC	**451**	631
Deferred state tax assets	**220**	117
Other	**246**	342
Total	**6,358**	5,241
Valuation allowance	**(2)**	(49)
Total deferred tax assets	**6,356**	5,192
Accumulated deferred income taxes	**$ 12,322**	$ 11,064

On November 20, 2015, the FASB issued ASU 2015-17, which simplifies the presentation of deferred income taxes. The new guidance resulted in a reclassification from deferred income taxes, current of $506 million , with $488 million to non-current accumulated deferred income taxes and $18 million to other deferred charges, as well as $2 million from accrued income taxes to non-current accumulated deferred income taxes in Southern Company's December 31, 2014 balance sheet. See Note 1 under "Recently Issued Accounting Standards" for additional information.

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation in 2015 and 2014.

At December 31, 2015 , Southern Company had subsidiaries with NOL carryforwards for the states of Georgia, Mississippi, New Mexico, and Florida totaling approximately $697 million , $3.0 billion , $133 million , and $115 million , respectively, which could result in net state income tax benefits of $27 million , $97 million , $5 million , and $4 million , respectively, if utilized. These NOLs expire between 2017 and 2035, but are expected to be fully utilized by 2029. During the second quarter 2015, an agreement was reached with the Georgia Department of Revenue that will allow Southern Company to utilize a portion of the NOL carryforward over a four -year period beginning in 2017. Consequently, Southern Company reversed the related valuation allowance and recognized approximately $24 million in net tax benefits. During 2015, approximately $87 million in New Mexico

NOLs expired resulting in a $3.5 million net state income tax increase and a corresponding decrease in the valuation allowance, with no tax impact.

At December 31, 2015 , the tax-related regulatory assets to be recovered from customers were $1.6 billion . 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, 2015 , the tax-related regulatory liabilities to be credited to customers were $187 million . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs for the traditional operating companies are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $21 million in 2015 , $22 million in 2014 , and $16 million in 2013 . Southern Power's deferred federal ITCs are amortized to income tax expense over the life of the asset. Credits amortized in this manner amounted to $19 million in 2015 , $11 million in 2014 , and $6 million in 2013 . Also, Southern Power received cash related to federal ITCs under the renewable energy incentives of $162 million , $74 million , and $158 million for the years ended December 31, 2015 , 2014 , and 2013 , respectively, which had a material impact on cash flows. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. The tax benefit of the related basis differences reduced income tax expense by $54 million in 2015 , $48 million in 2014 , and $31 million in 2013 .

At December 31, 2015 , Southern Company had federal ITC carryforwards which are expected to result in $554 million of federal income tax benefits. The federal ITC carryforwards begin expiring in 2034 but are expected to be fully utilized by 2020. Additionally, Southern Company had state ITC carryforwards for the state of Georgia totaling $188 million , which will expire between 2020 and 2026, but are expected to be fully utilized by 2022.

Effective Tax Rate

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

	2015	2014	2013
Federal statutory rate	**35.0 %**	35.0 %	35.0 %
State income tax, net of federal deduction	**1.9**	2.3	2.5
Employee stock plans dividend deduction	**(1.2)**	(1.4)	(1.6)
Non-deductible book depreciation	**1.2**	1.4	1.5
AFUDC-Equity	**(2.2)**	(2.9)	(2.6)
ITC basis difference	**(1.5)**	(1.6)	(1.2)
Other	**(0.3)**	(0.3)	(0.5)
Effective income tax rate	**32.9 %**	32.5 %	33.1 %

Southern Company's effective tax rate is typically lower than the statutory rate due to its employee stock plans' dividend deduction and non-taxable AFUDC equity.

Unrecognized Tax Benefits

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

	2015	2014	2013
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 170**	$ 7	$ 70
Tax positions increase from current periods	**43**	64	3
Tax positions increase from prior periods	**240**	102	—
Tax positions decrease from prior periods	**(20)**	(3)	(66)
Balance at end of year	**$ 433**	$ 170	$ 7

The tax positions increase from current periods and prior periods for 2015 and 2014 relate primarily to deductions for R&E expenditures associated with the Kemper IGCC. See Note 3 under "Integrated Coal Gasification Combined Cycle" and "Section 174 Research and Experimental Deduction" herein for more information. The tax positions decrease from prior periods for 2015 and 2014 relates to federal and state income tax credits. The tax positions decrease from prior periods for 2013 relate primarily to the Company's compliance with final U.S. Treasury regulations that resulted in a tax accounting method change for repairs.

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

	2015	2014	2013
		(in millions)	
Tax positions impacting the effective tax rate	**$ 10**	$ 10	$ 7
Tax positions not impacting the effective tax rate	**423**	160	—
Balance of unrecognized tax benefits	**$ 433**	$ 170	$ 7

The tax positions impacting the effective tax rate for 2015 , 2014 , and 2013 primarily relate to federal and state income tax credits. The tax positions not impacting the effective tax rate for 2015 and 2014 relate to deductions for R&E expenditures associated with the Kemper IGCC. See "Section 174 Research and Experimental Deduction" herein for more information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was immaterial for all years presented.

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

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 and 2014 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 Southern 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 reduced tax payments for 2015 and included in its 2013 and 2014 consolidated federal income tax returns deductions for R&E expenditures related to the Kemper IGCC. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures.

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. The IRS is currently reviewing the underlying support for the deduction, but has not completed its audit of these expenditures. Due to the uncertainty related to this tax position, Southern Company had related unrecognized tax benefits associated with these R&E deductions of approximately $423 million and associated interest of $9 million as of December 31, 2015. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC. The ultimate outcome of this matter cannot be determined at this time.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

Alabama Power has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to Alabama Power through the issuance of junior subordinated notes totaling $206 million as of December 31, 2015 and 2014 , which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. Alabama Power considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2015 and 2014 , trust preferred securities of $200 million were outstanding.

Securities Due Within One Year

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

	2015	2014
	(in millions)	
Senior notes	$ 1,810	$ 2,375
Other long-term debt	829	775
Pollution control revenue bonds	4	152
Capitalized leases	32	31
Unamortized debt issuance expense	(1)	(4)
Total	$ 2,674	$ 3,329

Maturities through 2020 applicable to total long-term debt are as follows: $2.7 billion in 2016 ; $2.4 billion in 2017 ; $1.7 billion in 2018 ; $1.2 billion in 2019 ; and $1.4 billion in 2020 .

Bank Term Loans

Southern Company and certain of the traditional operating companies have entered into various floating rate bank term loan agreements for loans bearing interest based on one-month LIBOR. At December 31, 2015 , Southern Company, Mississippi Power, and Southern Power had outstanding bank term loans totaling $400 million , $900 million , and $400 million , respectively, of which $1.23 billion are reflected in the statements of capitalization as long-term debt and $475 million are reflected in the balance sheet as notes payable. At December 31, 2014 , Mississippi Power had outstanding bank term loans totaling $775 million .

In September 2015, Southern Company entered into a $400 million aggregate principal amount 18 -month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes.

In April 2015, Mississippi Power entered into two short-term floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million , bearing interest based on one-month LIBOR. The proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million , working capital, and other general corporate purposes, including Mississippi Power's ongoing construction program. Mississippi Power also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016.

In August 2015, Southern Power Company entered into a $400 million aggregate principal amount 13 -month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes, including Southern Power's growth strategy and continuous construction program.

The outstanding bank loans as of December 31, 2015 have covenants that limit debt levels to a percentage of total capitalization. The percentage is 70% for Southern Company and 65% for Mississippi Power and Southern Power Company, as defined in the agreements. For purposes of these definitions, debt excludes any long-term debt payable to affiliated trusts, other hybrid securities, and, for Southern Company and Mississippi Power, any securitized debt relating to the securitization of certain costs of the Kemper IGCC. Additionally, for Southern Company and Southern Power Company, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power Company to the extent such debt is non-recourse to Southern Power Company and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2015 , each of Southern Company, Mississippi Power, and Southern Power Company was in compliance with its debt limits.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), Georgia Power and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) in February 2014, under which the DOE agreed to guarantee the obligations of Georgia Power under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, Georgia Power, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which Georgia Power may make term loan borrowings through the FFB.

Proceeds of advances made under the FFB Credit Facility are used to reimburse Georgia Power for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program

(Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion .

All borrowings under the FFB Credit Facility are full recourse to Georgia Power, and Georgia Power is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. Georgia Power's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on Georgia Power's ability to grant liens on other property.

Advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375% .

In February 2014, Georgia Power made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion . The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029, and is expected to be reset from time to time thereafter through 2044. In connection with its entry into the agreements with the DOE and the FFB, Georgia Power incurred issuance costs of approximately $66 million , which are being amortized over the life of the borrowings under the FFB Credit Facility.

In December 2014, Georgia Power made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million . The interest rate applicable to the $200 million advance in December 2014 under the FFB Credit Facility is 3.002% for an interest period that extends to 2044.

In June and December 2015, Georgia Power made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $600 million and $400 million , respectively. The interest rate applicable to the $600 million principal amount is 3.283% and the interest rate applicable to the $400 million principal amount is 3.072% , both for an interest period that extends to 2044.

Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Under the Loan Guarantee Agreement, Georgia Power is subject to customary borrower affirmative and negative covenants and events of default. In addition, Georgia Power is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and Georgia Power will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. Georgia Power also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Promissory Note, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume Georgia Power's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of Georgia Power's ownership interest in Plant Vogtle Units 3 and 4.

Senior Notes

Southern Company and its subsidiaries issued a total of $3.7 billion of senior notes in 2015 . Southern Company issued $600 million and its subsidiaries issued a total of $3.1 billion . The proceeds of these issuances were used to repay long-term indebtedness, to repay short-term indebtedness, and for other general corporate purposes, including the applicable subsidiaries' continuous construction programs, and, for Southern Power, its growth strategy.

At December 31, 2015 and 2014 , Southern Company and its subsidiaries had a total of $19.1 billion and $18.2 billion , respectively, of senior notes outstanding. At December 31, 2015 and 2014 , Southern Company had a total of $2.4 billion and $2.2 billion , respectively, of senior notes outstanding.

Subsequent to December 31, 2015, Alabama Power issued $400 million aggregate principal amount of Series 2016A 4.30% Senior Notes due January 2, 2046. The proceeds were used to repay at maturity $200 million aggregate principal amount of its Series FF 5.20% Senior Notes due January 15, 2016 and for general corporate purposes.

Since Southern Company is a holding company, the right of Southern Company and, hence, the right of creditors of Southern Company (including holders of Southern Company senior notes) to participate in any distribution of the assets of any subsidiary of Southern Company, whether upon liquidation, reorganization or otherwise, is subject to prior claims of creditors and preferred and preference stockholders of such subsidiary.

Junior Subordinated Notes

In October 2015, Southern Company issued $1.0 billion aggregate principal amount of Series 2015A 6.25% Junior Subordinated Notes due October 15, 2075. The proceeds were used to pay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the traditional operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. In some cases, the pollution control obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of pollution control bonds issued by public authorities. The traditional operating companies had $3.3 billion and $3.2 billion of outstanding pollution control revenue bonds at December 31, 2015 and December 31, 2014 , respectively. The traditional operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Plant Daniel Revenue Bonds

In 2011, in connection with Mississippi Power's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, Mississippi Power 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. See "Assets Subject to Lien" herein for additional information.

Other Revenue Bonds

Other revenue bond obligations represent loans to Mississippi Power 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.

Mississippi Power had $50 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2015 and 2014 . Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service and the related obligations are classified as long-term debt.

In 2013, Mississippi Power entered into a nitrogen supply agreement for the air separation unit of the Kemper IGCC, which resulted in a capital lease obligation at December 31, 2015 and 2014 of approximately $77 million and $80 million , respectively, with an annual interest rate of 4.9% for both years. Amortization of the capital lease asset for the air separation unit will begin when the Kemper IGCC is placed in service.

At December 31, 2015 and 2014 , the capitalized lease obligations for Georgia Power's corporate headquarters building were $35 million and $40 million , respectively, with an annual interest rate of 7.9% for both years.

At December 31, 2015 and 2014 , Alabama Power had a capitalized lease obligation of $5 million for a natural gas pipeline with an annual interest rate of 6.9% .

At December 31, 2015 and 2014 , a subsidiary of Southern Company had capital lease obligations of approximately $30 million and $34 million , respectively, for certain computer equipment including desktops, laptops, servers, printers, and storage devices with annual interest rates that range from 1.2% to 3.1% .

NOTES (continued)
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Other Obligations

In 2012, January 2014, and October 2014, Mississippi Power received $150 million , $75 million , and $50 million , respectively, interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. In 2013, Southern Company entered into an agreement with SMEPA under which Southern Company agreed to guarantee the obligations of Mississippi Power with respect to any required refund of the deposits. On May 20, 2015, SMEPA notified Mississippi Power of its termination of the asset purchase agreement between Mississippi Power and SMEPA. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, Mississippi Power issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures on December 1, 2017.

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Gulf Power has granted one or more liens on certain of its property in connection with the issuance of certain series of pollution control revenue bonds with an aggregate outstanding principal amount of $41 million as of December 31, 2015 .

The revenue bonds assumed in conjunction with Mississippi Power's purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. See "Plant Daniel Revenue Bonds" herein for additional information.

See "DOE Loan Guarantee Borrowings" above for information regarding certain borrowings of Georgia Power that are secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4.

Each of the Project Credit Facilities (defined below) is secured by the membership interests and assets of the subsidiary of Southern Power Company party to the agreement. See Note 12 under "Southern Power" for additional information.

Bank Credit Arrangements

At December 31, 2015 , committed credit arrangements with banks were as follows:

	Expires						Executable Term Loans		Due Within One Year	
Company	2016	2017	2018	2020	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)				*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company [(a)]	$ —	$ —	$ 1,000	$ 1,250	$ 2,250	$ 2,250	$ —	$ —	$ —	$ —
Alabama Power	40	—	500	800	1,340	1,340	—	—	—	40
Georgia Power	—	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	80	30	165	—	275	275	50	—	50	30
Mississippi Power	220	—	—	—	220	195	30	15	45	175
Southern Power [(b)]	—	—	—	600	600	566	—	—	—	—
Other	70	—	—	—	70	70	—	—	—	70
Total	$ 410	$ 30	$ 1,665	$ 4,400	$ 6,505	$ 6,428	$ 80	$ 15	$ 95	$ 315

(a) Excludes the $8.1 billion Bridge Agreement entered into in September 2015 that will be funded only to the extent necessary to provide financing for the Merger as discussed herein.

(b) Excludes credit agreements (Project Credit Facilities) assumed with the acquisition of certain solar facilities, which are non-recourse to Southern Power Company, the proceeds of which are being used to finance project costs related to such solar facilities currently under construction. See Note 12 under "Southern Power" for additional information.

As reflected in the table above, in August 2015, Southern Company, Alabama Power, Georgia Power, and Southern Power Company each amended and restated their multi-year credit arrangements, which, among other things, extended the maturity dates from 2018 to 2020. Southern Company and Southern Power Company increased their borrowing ability under these arrangements to $1.25 billion from $1.0 billion and to $600 million from $500 million , respectively. Georgia Power increased its borrowing ability by $150 million under its facility maturing in 2020 and terminated its aggregate $150 million facilities maturing in 2016. In September 2015, Southern Company entered into an additional multi-year credit arrangement for $1.0 billion with a maturity date of 2018. Alabama Power entered into a new $500 million three -year credit arrangement which replaced a majority of Alabama Power's bilateral credit arrangements. In November 2015, Gulf Power amended and restated certain of its multi-year credit arrangements which, among other things, extended the maturity dates for the majority of Gulf Power's agreements from 2016 to 2018.

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than $^{1}/_{4}$ of 1% for Southern Company, the traditional operating companies, and Southern Power Company. Compensating balances are not legally restricted from withdrawal.

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

Southern Company's credit arrangements contain covenants that limit debt level to 70% of total capitalization, as defined in the agreements, and most of these other bank credit arrangements contain covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements, other hybrid securities, and, for Southern Company and Mississippi Power, any securitized debt relating to the securitization of certain costs of the Kemper IGCC. Additionally, for Southern Company and Southern Power Company, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power Company to the extent such debt is non-recourse to Southern Power Company and capitalization excludes the capital stock or other equity attributable to such subsidiaries. At December 31, 2015 , Southern Company, the traditional operating companies, and Southern Power Company were each in compliance with their respective debt limit covenants.

A portion of the $6.4 billion unused credit with banks is allocated to provide liquidity support to the traditional operating companies' pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2015 was approximately $1.8 billion . In addition, at December 31, 2015 , the traditional operating companies had approximately $181 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

In addition, Southern Company entered into the $8.1 billion Bridge Agreement on September 30, 2015 to provide financing for the Merger in the event long-term financing is not available. The Bridge Agreement provides for total loan commitments in an aggregate amount of $8.1 billion to fund the payment of the cash consideration payable under the Merger Agreement and other cash payments required in connection with the consummation of the Merger, the Bridge Agreement and the borrowings thereunder, the other financing transactions related to the Merger, and the payment of fees and expenses incurred in connection with the foregoing. If funded, the loan under the Bridge Agreement will mature and be payable in full on the date that is 364 days after the funding of the commitments under the Bridge Agreement. As of December 31, 2015, Southern Company had no outstanding loans under the Bridge Agreement. See Note 12 under "Southern Company – Proposed Merger with AGL Resources" for additional information regarding the Merger.

Southern Company, the traditional operating companies, and Southern Power Company make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above, excluding the Bridge Agreement. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2015:		
Commercial paper	**$ 740**	**0.7%**
Short-term bank debt	**500**	**1.4%**
Total	**$ 1,240**	**0.9%**
December 31, 2014:		
Commercial paper	$ 803	0.3%
Short-term bank debt	—	—%
Total	$ 803	0.3%

In addition to the short-term borrowings in the table above, the Project Credit Facilities had total amounts outstanding as of December 31, 2015 of $137 million at a weighted average interest rate of 2.0% .

Redeemable Preferred Stock of Subsidiaries

Each of the traditional operating companies has issued preferred and/or preference stock. The preferred stock of Alabama Power and Mississippi Power contains a feature that allows the holders to elect a majority of such subsidiary's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of Alabama Power and Mississippi Power, this preferred stock is presented as "Redeemable Preferred Stock of Subsidiaries" in a manner consistent with temporary equity under applicable accounting standards. The preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power do not contain such a provision. As a result, under applicable accounting standards, the preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power are presented as "noncontrolling interests," a separate component of "Stockholders' Equity," on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

At December 31, 2015 , the outstanding redeemable preferred stock of subsidiaries of Southern Company was $118 million . At December 31, 2014 and 2013 , the outstanding redeemable preferred stock of subsidiaries of Southern Company was $375 million .

In May 2015, Alabama Power redeemed 6.48 million shares ($162 million aggregate stated capital) of its 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date and 4.0 million shares ($100 million aggregate stated capital) of its 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date. Additionally, $5 million of issuance costs were transferred from redeemable preferred stock of subsidiaries to common stockholder's equity upon redemption.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of the generating plants, the Southern Company system has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2015 , 2014 , and 2013 , the traditional operating companies and Southern Power incurred fuel expense of $4.8 billion , $6.0 billion , and $5.5 billion , respectively, the majority of which was purchased under long-term commitments. Southern Company expects that a substantial amount of the Southern Company system's future fuel needs will continue to be purchased under long-term commitments.

In addition, the Southern Company system has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases or have been used by a third party to secure financing. Total capacity expense under PPAs accounted for as operating leases was $227 million , $198 million , and $157 million for 2015 , 2014 , and 2013 , respectively.

Estimated total obligations under these commitments at December 31, 2015 were as follows:

	Operating Leases (*)	Other
	(in millions)	
2016	$ 233	$ 10
2017	242	8
2018	246	7
2019	249	8
2020	246	4
2021 and thereafter	1,291	47
Total	$ 2,507	$ 84

(*) A total of $304 million of biomass PPAs included under operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action.

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $130 million , $118 million , and $123 million for 2015 , 2014 , and 2013 , respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

As of December 31, 2015 , estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2016	$ 40	$ 81	$ 121
2017	25	78	103
2018	14	67	81
2019	6	55	61
2020	6	47	53
2021 and thereafter	16	690	706
Total	$ 107	$ 1,018	$ 1,125

For the traditional operating companies, a majority of the barge and railcar lease expenses are recoverable through fuel cost recovery provisions. In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $48 million . At the termination of the leases, the lessee may renew the lease or exercise its purchase option or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

Guarantees

In 2013, Georgia Power entered into an agreement that requires Georgia Power to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years . The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2017. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million .

As discussed above under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

During 2015 , Southern Company issued approximately 6.6 million shares of common stock primarily through the Omnibus Incentive Compensation Plan and received proceeds of approximately $256 million . During the first nine months of 2015, all sales under the Southern Investment Plan and the Employee Savings Plan were funded with shares acquired on the open market by independent plan administrators. In October 2015, Southern Company began issuing shares of common stock through the Southern Investment Plan and the Employee Savings Plan. The Company may satisfy its obligations with respect to the plans in several ways, including through using newly issued shares or treasury shares or acquiring shares on the open market through the independent plan administrators.

On March 2, 2015, Southern Company announced a program to repurchase up to 20 million shares of Southern Company common stock to offset all or a portion of the incremental shares issued under its employee and director stock plans, including through stock option exercises, until December 31, 2017. Repurchases may be made by means of open market purchases, privately negotiated transactions, or accelerated or other share repurchase programs, in accordance with applicable securities laws. Under this program, approximately 2.6 million shares were repurchased in 2015 at a total cost of approximately $115 million . No further repurchases under the program are anticipated.

Shares Reserved

At December 31, 2015 , a total of 106 million shares were reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (which includes stock options and performance share units as discussed below). Of the total 106 million shares reserved, there were 14 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2015 .

Stock-Based Compensation

Stock-based compensation, in the form of stock options and performance share units, may be granted through the Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2015 , there were 5,405 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. As a result, stock-based compensation granted to employees in 2015 consisted exclusively of performance share units.

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

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

Year Ended December 31	2014	2013
Expected volatility	14.6%	16.6%
Expected term *(in years)*	5	5
Interest rate	1.5%	0.9%
Dividend yield	4.9%	4.4%
Weighted average grant-date fair value	$2.20	$2.93

Southern Company's activity in the stock option program for 2015 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2014	39,929,319	$40.55
Exercised	4,032,729	36.84
Cancelled	146,684	42.31
Outstanding at December 31, 2015	**35,749,906**	**$40.96**
Exercisable at December 31, 2015	**25,857,590**	**$40.53**

The number of stock options vested, and expected to vest in the future, as of December 31, 2015 was not significantly different from the number of stock options outstanding at December 31, 2015 as stated above. As of December 31, 2015 , the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and the aggregate intrinsic value for the options outstanding and options exercisable was $209 million and $162 million , respectively.

For the years ended December 31, 2015 , 2014 , and 2013 , total compensation cost for stock option awards recognized in income was $6 million , $27 million , and $25 million , respectively, with the related tax benefit also recognized in income of $2 million , $10 million , and $10 million , respectively. As of December 31, 2015 , the total 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, 2015 , 2014 , and 2013 was $48 million , $125 million , and $77 million , respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $19 million , $48 million , and $30 million for the years ended December 31, 2015 , 2014 , and 2013 , respectively.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2015 , 2014 , and 2013 was $154 million , $400 million , and $204 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 which equates to the requisite service period for accounting purposes. 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. Southern 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 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, issued in 2015, 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.

In determining the fair value of the TSR-based awards issued to employees, the expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the awards. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	**2015**	2014	2013
Expected volatility	**12.9%**	12.6%	12.0%
Expected term *(in years)*	**3**	3	3
Interest rate	**1.0%**	0.6%	0.4%
Annualized dividend rate (*)	**N/A**	$2.03	$1.96
Weighted average grant-date fair value	**$46.38**	$37.54	$40.50

(*) Beginning in 2015, cash dividends paid on Southern Company's common stock are accumulated and payable in additional shares of Southern Company's common stock at the end of the three-year performance period and are embedded in the grant date fair value which equates to the grant date stock price.

Total unvested performance share units outstanding as of December 31, 2014 were 1,830,381 . During 2015 , 1,542,653 performance share units were granted, 812,740 performance share units were vested, and 79,902 performance share units were forfeited, resulting in 2,480,392 unvested performance share units outstanding at December 31, 2015 . In January 2016 , based on achievement of the TSR performance goal, a portion of the performance share award units granted in 2013 vested and 227,515 shares were issued at a share price of $46.80 for the three -year performance and vesting period ended December 31, 2015 .

For the years ended December 31, 2015 , 2014 , and 2013 , total compensation cost for performance share units recognized in income was $88 million , $33 million , and $31 million , respectively, with the related tax benefit also recognized in income of $34 million , $13 million , and $12 million , respectively. As of December 31, 2015 , there was $33 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 19 months .

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. The effect of both stock options and performance share award units was determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Average Common Stock Shares		
	2015	2014	2013
		(in millions)	
As reported shares	**910**	897	877
Effect of options and performance share award units	**4**	4	4
Diluted shares	**914**	901	881

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were 1 million and 7 million as of December 31, 2015 and 2014 , respectively.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2015 , consolidated retained earnings included $7.0 billion of undistributed retained earnings of the subsidiaries.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $13.5 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests in all licensed reactors, is $255 million and $247 million , respectively, per incident, but not more than an aggregate of $38 million and $37 million , respectively, per company to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years . The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, both companies have NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. In April 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks , with a maximum per occurrence per unit limit of $490 million . After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years . Alabama Power and Georgia Power each purchase limits based on the projected full cost of replacement power, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $55 million and $84 million , respectively.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by Alabama Power or Georgia Power, as applicable, and could have a material effect on Southern Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

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

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

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

As of December 31, 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)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Energy-related derivatives	$ —	$ 7	$ —	$ —	$ 7
Interest rate derivatives	—	22	—	—	22
Nuclear decommissioning trusts:(*)					
Domestic equity	541	69	—	—	610
Foreign equity	47	160	—	—	207
U.S. Treasury and government agency securities	—	152	—	—	152
Municipal bonds	—	64	—	—	64
Corporate bonds	11	278	—	—	289
Mortgage and asset backed securities	—	145	—	—	145
Private equity	—	—	—	17	17
Other	16	9	—	—	25
Cash equivalents	790	—	—	—	790
Other investments	9	—	1	—	10
Total	$ 1,414	$ 906	$ 1	$ 17	$ 2,338
Liabilities:					
Energy-related derivatives	$ —	$ 220	$ —	$ —	$ 220
Interest rate derivatives	—	30	—	—	30
Total	$ —	$ 250	$ —	$ —	$ 250

(*) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

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As of December 31, 2014 , 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, 2014:	**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:					
Energy-related derivatives	$ —	$ 13	$ —	$ —	$ 13
Interest rate derivatives	—	8	—	—	8
Nuclear decommissioning trusts:(*)					
Domestic equity	583	85	—	—	668
Foreign equity	34	184	—	—	218
U.S. Treasury and government agency securities	—	130	—	—	130
Municipal bonds	—	62	—	—	62
Corporate bonds	—	299	—	—	299
Mortgage and asset backed securities	—	139	—	—	139
Private equity	—	—	—	3	3
Other	11	13	—	—	24
Cash equivalents	397	—	—	—	397
Other investments	9	—	1	—	10
Total	$ 1,034	$ 933	$ 1	$ 3	$ 1,971
Liabilities:					
Energy-related derivatives	$ —	$ 201	$ —	$ —	$ 201
Interest rate derivatives	—	24	—	—	24
Total	$ —	$ 225	$ —	$ —	$ 225

(*) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflect the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available. See Note 1 under "Nuclear Decommissioning" for additional information.

"Other investments" include investments that are not traded in the open market. The fair value of these investments have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan executions.

Southern Company early adopted ASU 2015-07 effective December 31, 2015. As required, disclosures in the paragraphs and tables below are limited to only those investments in funds that are measured at net asset value as a practical expedient. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation.

As of December 31, 2015 and 2014 , the fair value measurements of private equity investments held in the nuclear decommissioning trust that are calculated at net asset value per share (or its equivalent) as a practical expedient, as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
As of December 31, 2015	**$ 17**	**$ 28**	**Not Applicable**	**Not Applicable**
As of December 31, 2014	$ 3	$ 7	Not Applicable	Not Applicable

Private equity funds include a fund-of-funds that invests in high quality private equity funds across several market sectors, a fund that invests in real estate assets, and a fund that acquires companies to create resale value. Private equity funds do not have redemption rights. Distributions from these funds will be received as the underlying investments in the funds are liquidated. Liquidations are expected to occur at various times over the next ten years .

As of December 31, 2015 and 2014 , 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, including securities due within one year:		
2015	**$ 27,216**	**$ 27,913**
2014	$ 23,814	$ 25,816

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 available to Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power.

11. DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 10 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 traditional operating companies and Southern Power enter into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel-hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The traditional operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in commodity fuel prices and prices of electricity because their long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the traditional operating companies and Southern Power may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted wholesale generating capacity is used to sell electricity.

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

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2015 , the net volume of energy-related derivative contracts for natural gas positions totaled 224 million mmBtu for the Southern Company system, with the longest hedge date of 2020 over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date of 2017 for derivatives not designated as hedges.

In addition to the volumes discussed above, the traditional operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 5 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2016 are immaterial for Southern Company.

Interest Rate Derivatives

Southern Company and certain subsidiaries may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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At December 31, 2015 , 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, 2015
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$ 1,000	3-month LIBOR	2.37%	November 2026	$ 1
	1,000	3-month LIBOR	2.70%	November 2046	(1)
	200	3-month LIBOR	2.93%	October 2025	(15)
	80	3-month LIBOR	2.32%	December 2026	1
Cash Flow Hedges of Existing Debt					
	250	3-month LIBOR + 0.32%	0.75%	March 2016	—
	200	3-month LIBOR + 0.40%	1.01%	August 2016	—
Fair Value Hedges of Existing Debt					
	250	1.30%	3-month LIBOR + 0.17%	August 2017	1
	300	2.75%	3-month LIBOR + 0.92%	June 2020	2
	250	5.40%	3-month LIBOR + 4.02%	June 2018	1
	200	4.25%	3-month LIBOR + 2.46%	December 2019	2
	500	1.95%	3-month LIBOR + 0.76%	December 2018	(3)
Derivatives not Designated as Hedges					
	65 (a,d)	3-month LIBOR	2.50%	October 2016 (e)	1
	47 (b,d)	3-month LIBOR	2.21%	October 2016 (e)	1
	65 (c,d)	3-month LIBOR	2.21%	November 2016 (f)	1
Total	$ 4,407				$ (8)

(a) Swaption at RE Tranquillity LLC. See Note 12 for additional information.
(b) Swaption at RE Roserock LLC. See Note 12 for additional information.
(c) Swaption at RE Garland Holdings LLC. See Note 12 for additional information.
(d) Amortizing notional amount.
(e) Represents the mandatory settlement date. Settlement amount will be based on a 15 -year amortizing swap.
(f) Represents the mandatory settlement date. Settlement amount will be based on a 12 -year amortizing swap.

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The estimated pre-tax gains (losses) that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2016 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2046 .

Derivative Financial Statement Presentation and Amounts

At December 31, 2015 and 2014 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 3**	$ 7	Liabilities from risk management activities	**$ 130**	$ 118
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**87**	79
Total derivatives designated as hedging instruments for regulatory purposes		**$ 3**	$ 7		**$ 217**	$ 197
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	**$ 3**	$ —	Liabilities from risk management activities	**$ 2**	$ —
Interest rate derivatives:	Other current assets	**19**	7	Liabilities from risk management activities	**23**	17
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**7**	7
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 22**	$ 8		**$ 32**	$ 24
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ 1**	$ 6	Liabilities from risk management activities	**$ 1**	$ 4
Interest rate derivatives:	Other current assets	**3**	—	Liabilities from risk management activities	**—**	—
Total derivatives not designated as hedging instruments		**$ 4**	$ 6		**$ 1**	$ 4
Total		**$ 29**	$ 21		**$ 250**	$ 225

NOTES (continued)
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The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts 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. Amounts related to energy-related derivative contracts and interest rate derivative contracts at December 31, 2015 and 2014 are presented in the following tables.

Fair Value					
Assets	**2015**	2014	**Liabilities**	**2015**	2014
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [a]	**$ 7**	$ 13	Energy-related derivatives presented in the Balance Sheet [a]	**$ 220**	$ 201
Gross amounts not offset in the Balance Sheet [b]	**(6)**	(9)	Gross amounts not offset in the Balance Sheet [b]	**(6)**	(9)
Net energy-related derivative assets	**$ 1**	$ 4	**Net energy-related derivative liabilities**	**$ 214**	$ 192
Interest rate derivatives presented in the Balance Sheet [a]	**$ 22**	$ 8	Interest rate derivatives presented in the Balance Sheet [a]	**$ 30**	$ 24
Gross amounts not offset in the Balance Sheet [b]	**(9)**	(8)	Gross amounts not offset in the Balance Sheet [b]	**(9)**	(8)
Net interest rate derivative assets	**$ 13**	**$ —**	**Net interest rate derivative liabilities**	**$ 21**	**$ 16**

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2015 and 2014 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (130)**	$ (118)	Other regulatory liabilities, current	**$ 3**	$ 7
	Other regulatory assets, deferred	**(87)**	(79)	Other regulatory liabilities, deferred	**—**	—
Total energy-related derivative gains (losses)		**$ (217)**	$ (197)		**$ 3**	$ 7

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2015**	2014	2013	**Statements of Income Location**	**2015**	2014	2013
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ (22)**	$ (16)	$ —	Interest expense, net of amounts capitalized	**$ (9)**	$ (8)	$ (14)

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effects of energy-related derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from OCI into earnings were immaterial for Southern Company.

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were immaterial and offset by changes to the carrying value of long-term debt.

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

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effects of energy-related and interest rate derivatives not designated as hedging instruments on the statements of income were immaterial for Southern Company.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At December 31, 2015 , Southern Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2015 , the fair value of derivative liabilities with contingent features was $52 million . The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $52 million and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

Southern Company, the traditional operating companies, and Southern Power are exposed to losses related to financial instruments in the event of counterparties' nonperformance. Southern Company, the traditional operating companies, and Southern Power only enter 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. Southern Company, the traditional operating companies, and Southern Power have also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate Southern Company's, the traditional operating companies', and Southern Power's exposure to counterparty credit risk. Therefore, Southern Company, the traditional operating companies, and Southern Power do not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

12. ACQUISITIONS

Southern Company

Proposed Merger with AGL Resources

On August 23, 2015, Southern Company entered into the Merger Agreement to acquire AGL Resources. Under the terms of the Merger Agreement, subject to the satisfaction or waiver (if permissible under applicable law) of specified conditions, Merger Sub will be merged with and into AGL Resources. AGL Resources will survive the Merger and become a wholly-owned, direct subsidiary of Southern Company. Upon the consummation of the Merger, each share of common stock of AGL Resources issued and outstanding immediately prior to the effective time of the Merger (Effective Time), other than shares owned by AGL Resources as treasury stock, shares owned by a subsidiary of AGL Resources, and any shares owned by shareholders who have properly exercised and perfected dissenters' rights, will be converted into the right to receive $66 in cash, without interest and less any applicable withholding taxes (Merger Consideration). Other equity-based securities of AGL Resources will be cancelled for cash consideration or converted into new awards from Southern Company as described in the Merger Agreement.

In accordance with GAAP, the Merger will be accounted for using the acquisition method of accounting whereby the assets acquired and liabilities assumed are recognized at fair value as of the acquisition date. The excess of the purchase price over the fair values of AGL Resources' assets and liabilities will be recorded as goodwill. Southern Company expects total cash of $8.2 billion to be required to fund the purchase price of approximately $8.0 billion to acquire AGL Resources common stock, options to purchase shares of AGL Resources common stock, and restricted stock units payable in shares of AGL Resources common stock and to fund acquisition-related expenses and financing costs of approximately $200 million . Southern Company will also assume AGL Resources' outstanding indebtedness.

The Merger was approved by AGL Resources' shareholders on November 19, 2015, and the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 expired on December 4, 2015. Consummation of the Merger remains subject to the satisfaction or waiver of certain closing conditions, including, among others, (i) the approval of the California Public Utilities Commission, Georgia PSC, Illinois Commerce Commission, Maryland PSC, and New Jersey Board of Public Utilities, and other approvals required under applicable state laws, and the approval of the Federal Communications Commission (FCC) for the transfer of control over the FCC licenses of certain subsidiaries of AGL Resources, (ii) the absence of a judgment, order, decision, injunction, ruling, or other finding or agency requirement of a governmental entity prohibiting the consummation of the Merger, and (iii) other customary closing conditions, including (a) subject to certain materiality qualifiers, the accuracy of each party's representations and warranties and (b) each party's performance in all material respects of its obligations under the Merger Agreement. Southern Company completed the required state regulatory applications in the fourth quarter 2015 and the required FCC filings in February 2016. On February 24, 2016, a stipulation and settlement agreement between Southern Company, AGL Resources, the Maryland PSC Staff, and the Maryland Office of People's Counsel was filed with the Maryland PSC. The proposed settlement remains subject to the approval of the Maryland PSC. Additionally, Southern Company received the approval of the Virginia State Corporation Commission in February 2016.

Subject to certain limitations, either party may terminate the Merger Agreement if the Merger is not consummated by August 23, 2016, which date may be extended by either party to February 23, 2017 if, on August 23, 2016, all conditions to closing other than those relating to (i) regulatory approvals and (ii) the absence of legal restraints preventing consummation of the Merger (to the extent relating to regulatory approvals) have been satisfied. Upon termination of the Merger Agreement under certain specified circumstances, AGL Resources will be required to pay Southern Company a termination fee of $201 million or reimburse Southern Company's expenses up to $5 million (which reimbursement shall reduce on a dollar-for-dollar basis any termination fee subsequently payable by AGL Resources). Southern Company currently expects to complete the transaction in the second half of 2016.

During 2015, the Company incurred external transaction costs for financing, legal, and consulting services associated with the proposed Merger of approximately $41 million .

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

Merger Financing

Southern Company intends to initially fund the cash consideration for the Merger using a mix of debt and equity. Southern Company expects to issue the debt to fund the Merger Consideration in several tranches including long-dated maturities. The amount of debt issued at each maturity will depend on prevailing market conditions at the time of the offering and other factors. In addition, Southern Company entered into the $8.1 billion Bridge Agreement on September 30, 2015 to provide financing for the Merger in the event long-term financing is not available. See Note 6 under "Bank Credit Arrangements" for additional information regarding the Bridge Agreement.

Proposed Acquisition of PowerSecure International, Inc. (Unaudited)

On February 24, 2016, Southern Company entered into an Agreement and Plan of Merger to acquire PowerSecure International, Inc. Under the terms of this merger agreement, the stockholders of PowerSecure International, Inc. will be entitled to receive $18.75 in cash for each share of common stock in a transaction with a total purchase price of approximately $431 million . Following this transaction, PowerSecure International, Inc. will become a wholly-owned subsidiary of Southern Company. This transaction is expected to close by the end of the second quarter 2016, subject to, among other items, approval by PowerSecure International, Inc. stockholders and notification, clearance, and reporting requirements under the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

Southern Power

During 2015 and 2014, in accordance with Southern Power's overall growth strategy, Southern Power acquired or contracted to acquire through its wholly-owned subsidiaries, Southern Renewable Partnerships, LLC or Southern Renewable Energy, Inc. (SRE), the projects set forth in the following table. Acquisition-related costs of approximately $4 million were expensed as incurred. The acquisitions do not include any contingent consideration unless specifically noted.

2015

Project Facility	Seller; Acquisition Date	Approx. Nameplate Capacity	Location	Southern Power Percentage Ownership		Expected/Actual COD	PPA Counterparties for Plant Output	PPA Contract Period	Approx. Purchase Price		
		(MW)							*(in millions)*		
WIND											
Kay Wind	Apex Clean Energy Holdings, LLC December 11, 2015	299	Kay County, OK	100%		December 12, 2015	Westar Energy, Inc. and Grant River Dam Authority	20 years	$	481	(b)
Grant Wind	Apex Clean Energy Holdings, LLC	151	Grant County, OK	100%		March 2016	Western Farmers, East Texas, and Northeast Texas Electric Cooperative	20 years	$	258	(c)
SOLAR											
Lost Hills Blackwell	First Solar, Inc. (First Solar) April 15, 2015	33	Kern County, CA	51%	(a)	April 17, 2015	City of Roseville, California/Pacific Gas and Electric Company	29 years	$	73	(d)
North Star	First Solar April 30, 2015	61	Fresno County, CA	51%	(a)	June 20, 2015	Pacific Gas and Electric Company	20 years	$	208	(e)
Tranquillity	Recurrent Energy, LLC August 28, 2015	205	Fresno County, CA	51%	(a)	Fourth quarter 2016	Shell Energy North America (US), LP and then Southern California Edison (SCE)	18 years	$	100	(f)
Desert Stateline	First Solar August 31, 2015	299	San Bernardino County, CA	51%	(a)	From December 2015 to third quarter 2016 (h)	SCE	20 years	$	439	(g)
Morelos	Solar Frontier Americas Holding, LLC October 22, 2015	15	Kern County, CA	90%		November 25, 2015	Pacific Gas and Electric Company	20 years	$	45	(i)
Roserock	Recurrent Energy, LLC November 23, 2015	160	Pecos County, TX	51%	(a)	Fourth quarter 2016	Austin Energy	20 years	$	45	(j)
Garland and Garland A	Recurrent Energy, LLC December 17, 2015	205	Kern County, CA	51%	(a)	Fourth quarter 2016	SCE	15 years and 20 years	$	49	(k)
Calipatria	Solar Frontier Americas Holding, LLC February 11, 2016	20	Imperial County, CA	90%		February 11, 2016	San Diego Gas & Electric Company	20 years	$	52	(l)

(a) Southern Power owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. Southern Power and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to the transaction. At each acquisition, Southern Power acquired a controlling interest in the entity owning the project facility and recorded approximately $227 million for the noncontrolling interests, in the aggregate, which is recorded as a non-cash transaction in contributions from noncontrolling interests and plant acquisitions.

(b) ***Kay Wind*** - The total purchase price, including $35 million of contingent consideration, is approximately $481 million . As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $481 million as CWIP, $8 million as a receivable related to transmission interconnection costs, and $8 million as payables; however, the allocation of the purchase price to individual assets has not been finalized.

(c) ***Grant Wind*** - On September 4, 2015, Southern Power entered into an agreement to acquire Grant Wind, LLC. The completion of the acquisition is subject to the seller achieving certain construction and project milestones as well as various other customary conditions to closing. The acquisition is expected to close at or near the expected COD. The purchase price includes approximately $24 million of contingent consideration and may be adjusted based on performance testing and production over the first 10 years of operation. The ultimate outcome of this matter cannot be determined at this time.

(d) ***Lost Hills Blackwell*** - Concurrent with the acquisition, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests for approximately $34 million . At the acquisition date, the members became contingently obligated to pay $3 million of construction payables through COD, making the aggregate purchase price approximately $107 million . The fair values of the assets acquired through the business combination were recorded as follows: $105 million as property, plant, and equipment, $3 million as a receivable related to transmission interconnection costs, and $4 million as construction and other payables; however, the allocation of the purchase price to individual assets has not been finalized.

(e) ***North Star*** - Concurrent with the acquisition, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests for approximately $99 million . At the acquisition date, the members became contingently obligated to pay $233 million of construction payables through COD, making the aggregate purchase price approximately $307 million . The fair values of the assets acquired through the business combination were recorded as follows: $266 million as property, plant, and equipment, $25 million as an intangible asset, $21 million as a receivable related to transmission interconnection costs, and $238 million as construction and other payables; however, the allocation of the purchase price to individual assets has not been finalized. The intangible asset consists of an acquired PPA that will be amortized over its 20 -year term. The amortization expense for the year ended December 31, 2015 was $1 million . The estimated amortization for future periods is approximately $1.2 million per year for 2016 through 2020, and $18 million thereafter.

(f) ***Tranquillity*** - Concurrent with the acquisition, a wholly-owned subsidiary of Recurrent Energy, LLC converted all its membership interests to 100% of the class B membership interests after contributing approximately $173 million of assets and receiving an initial distribution of $100 million . As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $186 million as CWIP, $24 million as other receivables, and $37 million as payables; however, the allocation of the purchase price to individual assets has not been finalized. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $473 million to $493 million . The ultimate outcome of this matter cannot be determined at this time.

(g) ***Desert Stateline*** - Concurrent with the acquisition, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests for approximately $223 million . As of December 31, 2015, the fair values of the assets acquired through the business combination, which includes Southern Power's and First Solar's initial payments due under the related construction agreement, were recorded as follows: $413 million as CWIP and $249 million as an intangible asset; however, the allocation of the purchase price to individual assets has not been finalized. The intangible asset consists of an acquired PPA that will be amortized over its 20 -year term. The estimated amortization for future periods is approximately $6.2 million in 2016, $12.5 million per year for 2017 through 2020, and $192.8 million thereafter. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $1.2 billion to $1.3 billion . The ultimate outcome of this matter cannot be determined at this time.

(h) ***Desert Stateline*** - The first three of eight phases were placed in service in December 2015. Subsequent to December 31, 2015, phases four and five were placed in service.

(i) ***Morelos*** - The total purchase price, including the minority owner, Turner Renewable Energy, LLC's (TRE) 10% ownership interest, is approximately $50 million . As of December 31, 2015, the fair values of the assets acquired through the business combination were recorded as follows: $49 million as property, plant, and equipment and $1 million as a receivable related to transmission interconnection costs; however, the allocation of the purchase price to individual assets has not been finalized.

(j) ***Roserock*** - Concurrent with the acquisition, a wholly-owned subsidiary of Recurrent Energy, LLC converted all its membership interests to 100% of the class B membership interests after contributing approximately $26 million of assets. As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $75 million as CWIP, $6 million as other receivables, and $10 million as payables and accrued expenses; however, the allocation of the purchase price to individual assets has not been finalized. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $333 million to $353 million . The ultimate outcome of this matter cannot be determined at this time.

(k) ***Garland and Garland A*** - Concurrent with the acquisition, a wholly-owned subsidiary of Recurrent Energy, LLC converted all its membership interests to 100% of the class B membership interests after contributing approximately $31 million of assets. As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $107 million as CWIP, $1 million as other deferred assets, and $28 million as payables and other accrued expenses; however, the allocation of the purchase price to individual assets has not been finalized. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $532 million to $552 million . The ultimate outcome of this matter cannot be determined at this time.

(l) ***Calipatria*** - The total purchase price, including the minority owner, TRE's 10% ownership interest, is approximately $58 million .

NOTES (continued)
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2014

Project Facility	Seller; Acquisition Date	Approx. Nameplate Capacity	Location	Southern Power Percentage Ownership		COD	PPA Counterparties for Plant Output	PPA Contract Period	Approx. Purchase Price	
		(MW)							*(in millions)*	
SOLAR										
Adobe	Sun Edison, LLC April 17, 2014	20	Kern County, CA	90%		May 21, 2014	SCE	20 years	$ 86	(b)
Macho Springs	First Solar Development, LLC May 22, 2014	50	Luna County, NM	90%		May 23, 2014	El Paso Electric Company	20 years	$ 117	(c)
Imperial Valley	First Solar, October 22, 2014	150	Imperial County, CA	51%	(a)	November 26, 2014	San Diego Gas & Electric Company	25 years	$ 505	(d)

(a) Southern Power owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. Southern Power and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to the transaction.

(b) ***Adobe*** - Total purchase price, including the minority owner TRE's 10% ownership interest, was $97 million . The fair values of the assets acquired were ultimately recorded as follows: $84 million to property, plant, and equipment, $15 million to prepayment related to transmission services, and $6 million to PPA intangible, resulting in a $5 million bargain purchase gain and a $3 million deferred tax liability. The bargain purchase gain is included in other income (expense), net. Acquisition-related costs were expensed as incurred and were not material.

(c) ***Macho Springs*** - Total purchase price, including the minority owner TRE's 10% ownership interest, was $130 million . The fair values of the assets acquired were ultimately recorded as follows: $128 million to property, plant, and equipment, $1 million to prepaid property taxes, and $1 million to prepayment related to transmission services. The acquisition did not include any contingent consideration. Acquisition-related costs were expensed as incurred and were not material.

(d) ***Imperial Valley*** - In connection with this acquisition, SG2 Holdings, LLC (SG2 Holdings) made an aggregate payment of approximately $128 million to a subsidiary of First Solar and became obligated to pay additional contingent consideration of approximately $599 million upon completion of the facility (representing the amount due to an affiliate of First Solar under the construction contract for Imperial Valley). When substantial completion was achieved in November 2014, a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The members of SG2 Holdings made additional agreed upon capital contributions totaling $593 million to SG2 Holdings that were used to pay the contingent consideration due, leaving $6.0 million of contingent consideration payable upon final acceptance of the facility. As a result of these capital contributions, the aggregate purchase price payable by Southern Power for the acquisition of Imperial Valley was approximately $505 million in addition to the $223 million noncash contribution by the minority member. The fair values of the assets acquired were ultimately recorded as follows: $708 million to property, plant, and equipment and $20 million to prepayment related to transmission services. Acquisition-related costs were expensed as incurred and were not material.

Construction Projects

During 2015, in accordance with Southern Power's overall growth strategy, Southern Power constructed or commenced construction of the projects set forth in the table below, in addition to the Tranquillity, Desert Stateline, Roserock, Garland, and Garland A facilities. Total cost of construction incurred for these projects during 2015 was $1.8 billion , of which $1.1 billion remains in CWIP at December 31, 2015 .

Solar Facility	Seller	Approx. Nameplate Capacity	County Location in Georgia	Expected/Actual COD	PPA Counterparties for Plant Output	PPA Contract Period	Estimated Construction Cost	
		(MW)					(in millions)	
Sandhills	N/A	146	Taylor	Fourth quarter 2016	Cobb, Flint, and Sawnee Electric Membership Corporations	25 years	$ 260 - 280	
Decatur Parkway	TradeWind Energy, Inc.	84	Decatur	December 31, 2015	Georgia Power [(a)]	25 years	Approx. $169	(c)
Decatur County	TradeWind Energy, Inc.	20	Decatur	December 29, 2015	Georgia Power	20 years	Approx. $46	(c)
Butler	CERSM, LLC and Community Energy, Inc.	103	Taylor	Fourth quarter 2016	Georgia Power [(b)]	30 years	$ 220 - 230	(c)
Pawpaw	Longview Solar, LLC	30	Taylor	March 2016	Georgia Power [(a)]	30 years	$ 70 - 80	(c)
Butler Solar Farm	Strata Solar Development, LLC	22	Taylor	February 10, 2016	Georgia Power	20 years	Approx. $45	(c)

(a) Affiliate PPA approved by the FERC.

(b) Affiliate PPA subject to FERC approval.

(c) Includes the acquisition price of all outstanding membership interests of the respective development entity.

13. SEGMENT AND RELATED INFORMATION

The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies – Alabama Power, Georgia Power, Gulf Power and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. 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's reportable business segments are the sale of electricity by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $417 million , $383 million , and $346 million in 2015 , 2014 , and 2013 , respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications and leveraged lease projects. All other inter-segment revenues are not material. Financial data for business segments and products and services for the years ended December 31, 2015 , 2014 , and 2013 was as follows:

NOTES (continued)
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	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
				(in millions)			
2015							
Operating revenues	**$ 16,491**	**$ 1,390**	**$ (439)**	**$ 17,442**	**$ 152**	**$ (105)**	**$ 17,489**
Depreciation and amortization	**1,772**	**248**	**—**	**2,020**	**14**	**—**	**2,034**
Interest income	**19**	**2**	**1**	**22**	**6**	**(5)**	**23**
Interest expense	**697**	**77**	**—**	**774**	**69**	**(3)**	**840**
Income taxes	**1,305**	**21**	**—**	**1,326**	**(132)**	**—**	**1,194**
Segment net income (loss) [(a)] [(b)]	**2,186**	**215**	**—**	**2,401**	**(32)**	**(2)**	**2,367**
Total assets	**69,052**	**8,905**	**(397)**	**77,560**	**1,819**	**(1,061)**	**78,318**
Gross property additions	**5,124**	**1,005**	**—**	**6,129**	**40**	**—**	**6,169**
2014							
Operating revenues	$ 17,354	$ 1,501	$ (449)	$ 18,406	$ 159	$ (98)	$ 18,467
Depreciation and amortization	1,709	220	—	1,929	16	—	1,945
Interest income	17	1	—	18	3	(2)	19
Interest expense	705	89	—	794	43	(2)	835
Income taxes	1,056	(3)	—	1,053	(76)	—	977
Segment net income (loss) [(a)] [(b)]	1,797	172	—	1,969	(3)	(3)	1,963
Total assets [(c)]	64,300	5,233	(131)	69,402	1,143	(312)	70,233
Gross property additions	5,568	942	—	6,510	11	1	6,522
2013							
Operating revenues	$ 16,136	$ 1,275	$ (376)	$ 17,035	$ 139	$ (87)	$ 17,087
Depreciation and amortization	1,711	175	—	1,886	15	—	1,901
Interest income	17	1	—	18	2	(1)	19
Interest expense	714	74	—	788	36	—	824
Income taxes	889	46	—	935	(85)	(1)	849
Segment net income (loss) [(a)] [(b)]	1,486	166	—	1,652	(10)	2	1,644
Total assets [(c)]	59,188	4,417	(101)	63,504	1,064	(304)	64,264
Gross property additions	5,226	633	—	5,859	9	—	5,868

(a) Attributable to Southern Company.

(b) Segment net income (loss) for the traditional operating companies includes pre-tax charges for estimated probable losses on the Kemper IGCC of $365 million ($226 million after tax) in 2015, $868 million ($536 million after tax) in 2014, and $1.2 billion ($729 million after tax) in 2013. See Note 3 under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" for additional information.

(c) Net of $202 million and $139 million of unamortized debt issuance costs as of December 31, 2014 and 2013, respectively. Also net of $488 million and $143 million of deferred tax assets as of December 31, 2014 and 2013, respectively. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Products and Services

Electric Utilities' Revenues				
Year	**Retail**	**Wholesale**	**Other**	**Total**
		(in millions)		
2015	**$ 14,987**	**$ 1,798**	**$ 657**	**$ 17,442**
2014	15,550	2,184	672	18,406
2013	14,541	1,855	639	17,035

NOTES (continued)
Southern Company and Subsidiary Companies 2015 Annual Report

14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2015 and 2014 is as follows:

				Per Common Share				
							Trading Price Range	
Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income Attributable to Southern Company	Basic Earnings	Diluted Earnings	Dividends	High	Low
		(in millions)						
March 2015	**$ 4,183**	**$ 957**	**$ 508**	**$ 0.56**	**$ 0.56**	**$ 0.5250**	**$ 53.16**	**$ 43.55**
June 2015	**4,337**	**1,098**	**629**	**0.69**	**0.69**	**0.5425**	**45.44**	**41.40**
September 2015	**5,401**	**1,649**	**959**	**1.05**	**1.05**	**0.5425**	**46.84**	**41.81**
December 2015	**3,568**	**578**	**271**	**0.30**	**0.30**	**0.5425**	**47.50**	**43.38**
March 2014	$ 4,644	$ 700	$ 351	$ 0.39	$ 0.39	$ 0.5075	$ 44.00	$ 40.27
June 2014	4,467	1,103	611	0.68	0.68	0.5250	46.81	42.55
September 2014	5,339	1,278	718	0.80	0.80	0.5250	45.47	41.87
December 2014	4,017	561	283	0.31	0.31	0.5250	51.28	43.55

As a result of the revisions to the cost estimate for the Kemper IGCC, Southern Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $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, and $380 million ($235 million after tax) in the first quarter 2014. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

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

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2011 through 2015
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	2015	2014	2013	2012	2011
Operating Revenues (in millions)	**$ 17,489**	$ 18,467	$ 17,087	$ 16,537	$ 17,657
Total Assets (in millions) [(a)(b)]	**$ 78,318**	$ 70,233	$ 64,264	$ 62,814	$ 58,986
Gross Property Additions (in millions)	**$ 6,169**	$ 6,522	$ 5,868	$ 5,059	$ 4,853
Return on Average Common Equity (percent)	**11.68**	10.08	8.82	13.10	13.04
Cash Dividends Paid Per Share of Common Stock	**$ 2.1525**	$ 2.0825	$ 2.0125	$ 1.9425	$ 1.8725
Consolidated Net Income Attributable to Southern Company (in millions)	**$ 2,367**	$ 1,963	$ 1,644	$ 2,350	$ 2,203
Earnings Per Share —					
Basic	**$ 2.60**	$ 2.19	$ 1.88	$ 2.70	$ 2.57
Diluted	**2.59**	2.18	1.87	2.67	2.55
Capitalization (in millions):					
Common stock equity	**$ 20,592**	$ 19,949	$ 19,008	$ 18,297	$ 17,578
Preferred and preference stock of subsidiaries and noncontrolling interests	**1,390**	977	756	707	707
Redeemable preferred stock of subsidiaries	**118**	375	375	375	375
Redeemable noncontrolling interests	**43**	39	—	—	—
Long-term debt [(a)]	**24,688**	20,644	21,205	19,143	18,492
Total (excluding amounts due within one year)	**$ 46,831**	$ 41,984	$ 41,344	$ 38,522	$ 37,152
Capitalization Ratios (percent):					
Common stock equity	**44.0**	47.5	46.0	47.5	47.3
Preferred and preference stock of subsidiaries and noncontrolling interests	**3.0**	2.3	1.8	1.8	1.9
Redeemable preferred stock of subsidiaries	**0.3**	0.9	0.9	1.0	1.0
Redeemable noncontrolling interests	**0.1**	0.1	—	—	—
Long-term debt [(a)]	**52.6**	49.2	51.3	49.7	49.8
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	**$ 22.59**	$ 21.98	$ 21.43	$ 21.09	$ 20.32
Market price per share:					
High	**$ 53.16**	$ 51.28	$ 48.74	$ 48.59	$ 46.69
Low	**41.40**	40.27	40.03	41.75	35.73
Close (year-end)	**46.79**	49.11	41.11	42.81	46.29
Market-to-book ratio (year-end) (percent)	**207.2**	223.4	191.8	203.0	227.8
Price-earnings ratio (year-end) (times)	**18.0**	22.4	21.9	15.9	18.0
Dividends paid (in millions)	**$ 1,959**	$ 1,866	$ 1,762	$ 1,693	$ 1,601
Dividend yield (year-end) (percent)	**4.6**	4.2	4.9	4.5	4.0
Dividend payout ratio (percent)	**82.7**	95.0	107.1	72.0	72.7
Shares outstanding (in thousands):					
Average	**910,024**	897,194	876,755	871,388	856,898
Year-end	**911,721**	907,777	887,086	867,768	865,125
Stockholders of record (year-end)	**131,771**	137,369	143,800	149,628	155,198
Traditional Operating Company Customers (year-end) (in thousands):					
Residential	**3,928**	3,890	3,859	3,832	3,809
Commercial [(c)]	**591**	587	582	579	578
Industrial [(c)]	**16**	16	16	16	16
Other	**11**	11	10	9	9
Total	**4,546**	4,504	4,467	4,436	4,412
Employees (year-end)	**26,703**	26,369	26,300	26,439	26,377

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $202 million, $139 million, $133 million, and $156 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-03. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(b) A reclassification of deferred tax assets from Total Assets of $488 million, $143 million, $202 million, and $125 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-17. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(c) A reclassification of customers from commercial to industrial is reflected for years 2011-2013 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (continued)
For the Periods Ended December 2011 through 2015
Southern Company and Subsidiary Companies 2015 Annual Report

	2015	2014	2013	2012	2011
Operating Revenues (in millions):					
Residential	**$ 6,383**	$ 6,499	$ 6,011	$ 5,891	$ 6,268
Commercial	**5,317**	5,469	5,214	5,097	5,384
Industrial	**3,172**	3,449	3,188	3,071	3,287
Other	**115**	133	128	128	132
Total retail	**14,987**	15,550	14,541	14,187	15,071
Wholesale	**1,798**	2,184	1,855	1,675	1,905
Total revenues from sales of electricity	**16,785**	17,734	16,396	15,862	16,976
Other revenues	**704**	733	691	675	681
Total	**$ 17,489**	$ 18,467	$ 17,087	$ 16,537	$ 17,657
Kilowatt-Hour Sales (in millions):					
Residential	**52,121**	53,347	50,575	50,454	53,341
Commercial	**53,525**	53,243	52,551	53,007	53,855
Industrial	**53,941**	54,140	52,429	51,674	51,570
Other	**897**	909	902	919	936
Total retail	**160,484**	161,639	156,457	156,054	159,702
Wholesale sales	**30,505**	32,786	26,944	27,563	30,345
Total	**190,989**	194,425	183,401	183,617	190,047
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.25**	12.18	11.89	11.68	11.75
Commercial	**9.93**	10.27	9.92	9.62	10.00
Industrial	**5.88**	6.37	6.08	5.94	6.37
Total retail	**9.34**	9.62	9.29	9.09	9.44
Wholesale	**5.89**	6.66	6.88	6.08	6.28
Total sales	**8.79**	9.12	8.94	8.64	8.93
Average Annual Kilowatt-Hour					
Use Per Residential Customer	**13,318**	13,765	13,144	13,187	13,997
Average Annual Revenue					
Per Residential Customer	**$ 1,630**	$ 1,679	$ 1,562	$ 1,540	$ 1,645
Plant Nameplate Capacity					
Ratings (year-end) (megawatts)	**44,223**	46,549	45,502	45,740	43,555
Maximum Peak-Hour Demand (megawatts):					
Winter	**36,794**	37,234	27,555	31,705	34,617
Summer	**36,195**	35,396	33,557	35,479	36,956
System Reserve Margin (at peak) (percent) (a)	**33.2**	19.8	21.5	20.8	19.2
Annual Load Factor (percent)	**59.9**	59.6	63.2	59.5	59.0
Plant Availability (percent) (b) :					
Fossil-steam	**86.1**	85.8	87.7	89.4	88.1
Nuclear	**93.5**	91.5	91.5	94.2	93.0
Source of Energy Supply (percent):					
Coal	**32.3**	39.3	36.9	35.2	48.7
Nuclear	**15.2**	14.8	15.5	16.2	15.0
Hydro	**2.6**	2.5	3.9	1.7	2.1
Oil and gas	**43.5**	37.4	37.3	38.3	28.0
Purchased power	**6.4**	6.0	6.4	8.6	6.2
Total	**100.0**	100.0	100.0	100.0	100.0

(a) Beginning in 2014, system reserve margin is calculated to include unrecognized capacity.
(b) Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

ALABAMA POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Alabama Power Company 2015 Annual Report

The management of Alabama Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (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, 2015 .

/s/ Mark A. Crosswhite
Mark A. Crosswhite
Chairman, President, and Chief Executive Officer

/s/ Philip C. Raymond
Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer

February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2015 and 2014 , and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2015 . 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 II-159 to II-203) present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2015 and 2014 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015 , in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Birmingham, Alabama
February 26, 2016

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NDR	Natural Disaster Reserve
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
Rate CNP	Rate Certificated New Plant
Rate CNP Compliance	Rate Certificated New Plant Compliance
Rate CNP Environmental	Rate Certificated New Plant Environmental
Rate CNP PPA	Rate Certificated New Plant Power Purchase Agreement
Rate ECR	Rate Energy Cost Recovery
Rate NDR	Rate Natural Disaster Reserve
Rate RSE	Rate Stabilization and Equalization plan
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries

DEFINITIONS
(continued)

Term	Meaning
traditional operating companies	Alabama Power Company, Georgia Power, Gulf Power, and Mississippi Power

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Alabama Power Company 2015 Annual Report

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. The Company has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Key Performance Indicators

The Company continues to focus on several key performance indicators including customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to 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 of these surveys in measuring performance, which the Company achieved during 2015.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's fossil/hydro 2015 Peak Season EFOR of 1.89% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's performance for 2015 was below the target for transmission reliability measures primarily due to the level of storm activity in the service territory during the year and was better than target for distribution reliability measures.

The Company uses net income after dividends on preferred and preference stock as the primary measure of the Company's financial performance. See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Earnings

The Company's 2015 net income after dividends on preferred and preference stock was $785 million, representing a $24 million, or 3.2%, increase over the previous year. The increase was due primarily to an increase in rates under Rate RSE effective January 1, 2015. This increase was partially offset by a decrease in weather-related revenues resulting from milder weather experienced in 2015 as compared to 2014 and an increase in amortization.

The Company's 2014 net income after dividends on preferred and preference stock was $761 million, representing a $49 million, or 6.9%, increase over the previous year. The increase was due primarily to an increase in weather-related revenues resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013, an increase in revenues related to net investments under Rate CNP Environmental, and an increase in AFUDC resulting from increased capital expenditures. The factors increasing net income were partially offset by an increase in total operating expenses.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2015	**2015**	2014
		(in millions)	
Operating revenues	**$ 5,768**	**$ (174)**	$ 324
Fuel	**1,342**	**(263)**	(26)
Purchased power	**351**	**(34)**	156
Other operations and maintenance	**1,501**	**33**	179
Depreciation and amortization	**643**	**40**	(42)
Taxes other than income taxes	**368**	**12**	8
Total operating expenses	**4,205**	**(212)**	275
Operating income	**1,563**	**38**	49
Allowance for equity funds used during construction	**60**	**11**	17
Interest income	**15**	**—**	(1)
Interest expense, net of amounts capitalized	**274**	**19**	(4)
Other income (expense), net	**(47)**	**(25)**	14
Income taxes	**506**	**(6)**	34
Net income	**811**	**11**	49
Dividends on preferred and preference stock	**26**	**(13)**	—
Net income after dividends on preferred and preference stock	**$ 785**	**$ 24**	$ 49

Operating Revenues

Operating revenues for 2015 were $5.8 billion, reflecting a $174 million decrease from 2014. Details of operating revenues were as follows:

	Amount	
	2015	2014
	(in millions)	
Retail — prior year	**$ 5,249**	$ 4,952
Estimated change resulting from —		
Rates and pricing	**204**	81
Sales growth (decline)	**(11)**	7
Weather	**(43)**	85
Fuel and other cost recovery	**(165)**	124
Retail — current year	**5,234**	5,249
Wholesale revenues —		
Non-affiliates	**241**	281
Affiliates	**84**	189
Total wholesale revenues	**325**	470
Other operating revenues	**209**	223
Total operating revenues	**$ 5,768**	$ 5,942
Percent change	**(2.9)%**	5.8%

Retail revenues in 2015 were $5.2 billion. These revenues decreased $15 million, or 0.3%, in 2015 and increased $297 million, or 6.0%, in 2014, each as compared to the prior year. The decrease in 2015 was due to decreased fuel revenues and milder weather in

2015 as compared to 2014, partially offset by increased revenues due to a Rate RSE increase effective January 1, 2015. The increase in 2014 was due to increased fuel revenues, colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013, and increased revenues related to net investments under Rate CNP Environmental primarily resulting from the inclusion of pre-2005 environmental assets. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information. See "Energy Sales" herein for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

Fuel rates billed to customers are designed to fully recover fluctuating fuel and purchased power costs over a period of time. Fuel revenues generally have no effect on net income because they represent the recording of revenues to offset fuel and purchased power expenses. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate ECR" for additional information.

Wholesale revenues from power sales to non-affiliated utilities were as follows:

	2015	2014	2013
		(in millions)	
Capacity and other	**$ 140**	$ 154	$ 143
Energy	**101**	127	105
Total non-affiliated	**$ 241**	$ 281	$ 248

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and 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. Short-term opportunity energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

In 2015, wholesale revenues from sales to non-affiliates decreased $40 million, or 14.2%, as compared to the prior year. This decrease reflects a $26 million decrease in revenues from energy sales and a $14 million decrease in capacity revenues. In 2015, KWH sales decreased 6.3% primarily due to the market availability of lower cost natural gas resources and an 8.4% decrease in the price of energy due to lower natural gas prices. In 2014, wholesale revenues from sales to non-affiliates increased $33 million, or 13.3%, as compared to the prior year primarily due to the availability of the Company's lower cost generation. This increase reflects a $22 million increase in revenues from energy sales and an $11 million increase in capacity revenues. In 2014, KWH sales increased 12.3% primarily due to the availability of the Company's lower cost generation and a 1.1% increase in the price of energy primarily due to higher natural gas prices.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales and purchases 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 and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clause.

In 2015, wholesale revenues from sales to affiliates decreased $105 million, or 55.6%, as compared to the prior year. In 2015, KWH sales decreased 33.9% as a result of lower cost generation in the Southern Company system and a 32.8% decrease in the price of energy primarily due to lower natural gas prices. In 2014, wholesale revenues from sales to affiliates decreased $23 million, or 10.8%, as compared to the prior year primarily related to a decrease in revenue from energy sales. In 2014, KWH sales decreased 21.7% primarily due to decreased hydro generation as the result of less rainfall as well as the addition of new generation in the Southern Company system, partially offset by a 13.7% increase in the price of energy primarily due to higher natural gas prices.

In 2015, other operating revenues decreased $14 million, or 6.3%, as compared to the prior year primarily due to decreases in co-generation steam revenues due to lower natural gas prices and transmission revenues related to the open access transmission tariff, partially offset by an increase in transmission service agreement revenues. In 2014, other operating revenues increased $17 million, or 8.3%, as compared to the prior year primarily due to increases in open access transmission tariff revenues, transmission service agreement revenues, and co-generation steam revenues.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2015 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2015	**2015**	2014	**2015**	2014
	(in billions)				
Residential	**18.1**	**(3.4)%**	4.5%	**0.1 %**	(0.8)%
Commercial	**14.1**	**(0.1)**	1.6	**0.1**	(1.3)
Industrial	**23.4**	**(1.8)**	3.9	**(1.8)**	3.9
Other	**0.2**	**(4.9)**	—	**(4.9)**	—
Total retail	**55.8**	**(1.9)**	3.5	**(0.7)%**	1.0 %
Wholesale —					
Non-affiliates	**4.3**	**(6.3)**	12.3		
Affiliates	**3.8**	**(33.8)**	(21.7)		
Total wholesale	**8.1**	**(21.5)**	(9.4)		
Total energy sales	**63.9**	**(4.9)%**	1.3%		

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 in 2015 were 1.9% lower than in 2014. Residential and commercial sales decreased 3.4% and 0.1%, respectively, due primarily to milder weather in 2015 as compared to 2014. Weather-adjusted residential and commercial sales were flat in 2015. Industrial sales decreased 1.8% in 2015 compared to 2014 as a result of a decrease in demand resulting from changes in production levels primarily in the primary metals sector. A strong dollar, low oil prices, and weak global growth conditions have constrained growth in the industrial sector in 2015.

Retail energy sales in 2014 were 3.5% higher than in 2013. Residential and commercial sales increased 4.5% and 1.6%, respectively, due primarily to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. Weather-adjusted residential and commercial sales decreased 0.8% and 1.3%, respectively, due primarily to a decrease in customer demand in 2014 compared to 2013. Industrial sales increased 3.9% in 2014 compared to 2013 as a result of an increase in demand resulting from changes in production levels primarily in the primary metals, chemicals, automotive and plastics, and stone, clay, and glass sectors. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

See "Operating Revenues" above for a discussion of significant changes in wholesale revenues from sales to non-affiliates and wholesale revenues from sales to affiliated companies as related to changes in price and KWH sales.

Fuel and Purchased Power Expenses

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2015 Annual Report

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

	2015	2014	2013
Total generation *(billions of KWHs)*	**60.9**	63.6	65.3
Total purchased power *(billions of KWHs)*	**6.3**	6.6	4.0
Sources of generation *(percent)* —			
Coal	**54**	54	53
Nuclear	**24**	23	21
Gas	**16**	17	17
Hydro	**6**	6	9
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**2.83**	3.14	3.29
Nuclear	**0.81**	0.84	0.84
Gas	**2.94**	3.69	3.38
Average cost of fuel, generated *(cents per net KWH)* (a)	**2.34**	2.68	2.73
Average cost of purchased power *(cents per net KWH)* (b)	**5.66**	5.92	5.76

(a) KWHs generated by hydro are excluded from the average cost of fuel, generated.

(b) Average cost of purchased power includes fuel, energy, and transmission purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $1.7 billion in 2015, a decrease of $297 million, or 14.9%, compared to 2014. The decrease was primarily due to a $184 million decrease in the average cost of fuel, a $79 million decrease in the volume of KWHs generated, an $18 million decrease related to the volume of KWHs purchased, and a $16 million decrease in the average cost of purchased power.

Fuel and purchased power expenses were $2.0 billion in 2014, an increase of $130 million, or 7.0%, compared to 2013. The increase was primarily due to a $147 million increase related to the volume of KWHs purchased and a $10 million increase in the average cost of purchased power. These increases were partially offset by a $19 million decrease in the average cost of fuel and an $8 million decrease in the volume of KWHs generated.

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 energy cost recovery clause. The Company, along with the Alabama PSC, continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate ECR" for additional information.

Fuel

Fuel expenses were $1.3 billion in 2015, a decrease of $263 million, or 16.4%, compared to 2014. The decrease was primarily due to a 20.4% decrease in the average cost of KWHs generated by natural gas, which excludes tolling agreements, a 9.9% decrease in the average cost of KWHs generated by coal, an 8.5% decrease in the volume of KWHs generated by natural gas, and a 4.0% decrease in the volume of KWHs generated by coal. Fuel expenses were $1.6 billion in 2014, a decrease of $26 million, or 1.6%, compared to 2013. The decrease was primarily due to a 4.5% decrease in the average cost of KWHs generated by coal, partially offset by a 30.8% decrease in the volume of KWHs generated by hydro facilities as a result of less rainfall, and a 9.2% increase in the average cost of KWHs generated by natural gas, which excludes tolling agreements.

Purchased Power – Non-Affiliates

In 2015, purchased power expense from non-affiliates was $171 million, a decrease of $14 million, or 7.6%, compared to 2014. The decrease was primarily due to a 19.5% decrease in the average cost per KWH purchased primarily due to lower gas prices partially offset by a 15.2% increase in the amount of energy purchased due to the market availability of lower cost generation. In 2014, purchased power expense from non-affiliates was $185 million, an increase of $85 million, or 85.0%, compared to 2013. The increase was primarily due to a 42.1% increase in the average cost per KWH purchased primarily due to demand during peak periods and a 28.8% increase in the amount of energy purchased to meet the demand created during cold weather in the first quarter 2014 and the addition of a new PPA in 2014.

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

Purchased Power – Affiliates

Purchased power expense from affiliates was $180 million in 2015, a decrease of $20 million, or 10.0%, compared to 2014. This decrease was primarily due to a 16.9% decrease in the amount of energy purchased due to milder weather in 2015 as compared to 2014, partially offset by an 8.3% increase in the average cost per KWH purchased related to steam support at Plant Gaston. Purchased power expense from affiliates was $200 million in 2014, an increase of $71 million, or 55.0%, compared to 2013. This increase was primarily due to a 96.4% increase in the amount of energy purchased to meet the demand created during cold weather in the first quarter 2014, partially offset by a 20.8% decrease in the average cost per KWH purchased due to the availability of lower cost Southern Company system generation at the time of purchase.

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

In 2015, other operations and maintenance expenses increased $33 million, or 2.2%, as compared to the prior year. Administrative and general expenses increased $53 million primarily due to increased employee benefit costs including pension costs. Nuclear production expenses increased $19 million primarily due to outage amortization costs. These increases were partially offset by a decrease in steam production costs of $21 million primarily due to timing of outages. Distribution expenses decreased $12 million primarily due to overhead line maintenance expenses.

In 2014, other operations and maintenance expenses increased $179 million, or 13.9%, as compared to the prior year. Steam production, other power generation, and hydro generation expenses increased $110 million primarily due to scheduled outage costs. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost of Removal Accounting Order" for additional information. Distribution and transmission expenses increased $31 million primarily related to increases in maintenance and labor expenses. Nuclear production expenses increased $14 million primarily related to labor expenses.

Depreciation and Amortization

Depreciation and amortization increased $40 million, or 6.6%, in 2015 as compared to the prior year. The increase in 2015 was primarily due to the amortization of $120 million of the regulatory liability for other cost of removal obligations in 2014, partially offset by decreases due to lower depreciation rates as a result of the depreciation study implemented in January 2015. Depreciation and amortization decreased $42 million, or 6.5%, in 2014 as compared to the prior year. The decrease in 2014 was primarily due to the amortization of $120 million of the regulatory liability for other cost of removal obligations, partially offset by increases due to depreciation rates related to environmental assets and amortization of certain regulatory assets. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost of Removal Accounting Order" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $12 million, or 3.4%, in 2015 as compared to the prior year. The increase was primarily due to increases in state and municipal utility license tax bases primarily due to an increase in retail revenues. In addition, there were increases in ad valorem taxes primarily due to an increase in assessed value of property.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $11 million, or 22.4%, in 2015 and $17 million, or 53.1% in 2014 as compared to the prior year primarily due to an increase in construction projects related to environmental and steam generation. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $19 million, or 7.5%, in 2015 as compared to the prior year. The increase in 2015 was primarily due to timing of debt issuances and redemptions partially offset by a decrease in interest rates. See FUTURE EARNINGS POTENTIAL – "Financing Activities" herein for additional information.

Other Income (Expense), Net

Other income (expense), net decreased $25 million, or 113.6%, in 2015 as compared to the prior year. The decrease in 2015 was primarily due to an increase in donations and a decrease in sales of non-utility property. Other income (expense), net increased $14 million, or 38.9%, in 2014 as compared to the prior year primarily due to a decrease in non-operating expenses and an increase in sales of non-utility property.

Income Taxes

Income taxes increased $34 million, or 7.1%, in 2014 as compared to the prior year primarily due to higher pre-tax earnings.

Dividends on Preferred and Preference Stock

Dividends on preferred and preference stock decreased $13 million, or 33.3%, in 2015 as compared to the prior year. The decrease in 2015 was primarily due to the redemption in May 2015 of certain series of preferred and preference stock. See Note 6 to the financial statements under "Redeemable Preferred Stock" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, 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 partially 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.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. Environmental compliance costs are recovered through Rate CNP Compliance. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP" for additional information. 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2015 Annual Report

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 2015 , the Company had invested approximately $3.9 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $349 million, $355 million, and $184 million for 2015 , 2014 , and 2013 , respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $851 million from 2016 through 2018 , with annual totals of approximately $319 million, $263 million, and $269 million for 2016 , 2017 , and 2018 , respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with closure in place and ground water monitoring of ash ponds in accordance with the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation (ARO) liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, 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 Accounting Order" herein for additional information on planned unit retirements and fuel conversions at the Company.

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. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. The compliance deadline set by the final MATS rule was April 16, 2015, with provisions for extensions to April 16, 2016. The implementation strategy for the MATS rule includes emission controls, retirements, and fuel conversions to achieve compliance by the deadlines applicable to each Company unit. On June 29, 2015, the U.S. Supreme Court issued a decision finding that in developing the MATS rule the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units. On December 15, 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule to the EPA without vacatur to respond to the U.S. Supreme Court's decision. The EPA's supplemental finding in response to the U.S. Supreme Court's decision, which the EPA proposes to finalize in April 2016, is not expected to have any impact on the MATS rule compliance requirements and deadlines.

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. On October 26, 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 will recommend area designations by October 2016, and the EPA is expected to finalize them by October 2017.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS , and the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard in December 2014, and no new nonattainment areas were designated within the Company's service territory.

Final revisions to the NAAQS for sulfur dioxide (SO_2) , which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has finalized a data requirements rule to support additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

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

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I having begun in 2015 and Phase II beginning in 2017. On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Alabama, but rejected all other pending challenges to the rule. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. On December 3, 2015, the EPA published a proposed revision to CSAPR that would revise existing ozone-season emissions budgets for nitrogen oxide in Alabama. The EPA proposes to finalize this rulemaking by summer 2016.

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.

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

On June 12, 2015, the EPA published a final rule requiring certain states (including Alabama) 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) by no later than November 22, 2016.

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. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, the Alabama opacity rule, CSAPR, regional haze regulations, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. 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.

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 October 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

On November 3, 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 National Pollutant Discharge Elimination System 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. The ultimate impact of these requirements will depend on pending and any future legal challenges, compliance dates, and implementation of the final rule and cannot be determined at this time.

On June 29, 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 August 28, 2015, but on October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The ultimate impact of the final rule will depend on the outcome of this and other pending legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs.

Coal Combustion Residuals

The Company currently manages CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at six generating plants. 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 State of Alabama has its own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On April 17, 2015, the EPA published the CCR Rule in the Federal Register, which became effective on October 19, 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. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

Based on initial cost estimates for closure in place and groundwater monitoring primarily related to ash ponds pursuant to the CCR Rule, the Company 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, 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. The Company is currently completing an analysis of the plan of closure for all ash ponds, including the timing of closure and related cost recovery through regulated rates subject to Alabama PSC approval. Based on the results of that analysis, the Company may accelerate the timing of some ash pond closures which could increase its ARO liabilities from the amounts presently recorded. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. Costs associated with the CCR Rule are expected to be recovered through Rate CNP Compliance. 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, 2015.

Global Climate Issues

On October 23, 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 its review with the courts. The stay will remain in effect through the resolution of the litigation, whether resolved in the U.S. Court of Appeals for the District of Columbia Circuit or 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. 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 Company's ongoing review of the final rules; the outcome of legal challenges, including legal challenges filed by the traditional operating companies; individual state implementation of the EPA's final guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

The United Nations 21st international climate change conference took place in late 2015. The result was the adoption of 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 increasing those commitments every five years. The ultimate impact of this agreement depends on its ratification and implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2014 greenhouse gas emissions were approximately 40 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2015 greenhouse gas emissions on the same basis is approximately 38 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

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 operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional 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 operating companies and in some adjacent areas. The FERC directed the traditional 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 operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

The Company 's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Alabama PSC. The Company currently recovers its costs from the regulated retail business primarily through Rate RSE, Rate CNP, Rate ECR, and Rate NDR. In addition, the Alabama PSC issues accounting orders to address current events impacting the Company. See Note 1 to the financial statements and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's rate mechanisms and accounting orders.

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon the Company's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If the Company's actual retail return is above the allowed WCE range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

On November 30, 2015, the Company made its annual Rate RSE submission to the Alabama PSC of projected data for 2016. Projected earnings were within the specified WCE range; therefore, retail rates under Rate RSE remained unchanged for 2016.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 3, 2015, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2015 through March 31, 2016. No adjustment to Rate CNP PPA is expected in 2016.

Rate CNP Environmental allowed for the recovery of the Company's retail costs associated with environmental laws, regulations, and other such mandates. On March 3, 2015, the Alabama PSC approved a modification to Rate CNP Environmental to include compliance costs for both environmental and non-environmental mandates. The recoverable non-environmental compliance costs result from laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. This modification to Rate CNP Environmental was effective March 20, 2015 with the revised rate now defined as Rate CNP Compliance. The Company was limited to recover $50 million of non-environmental compliance costs for the year 2015. Additional non-environmental compliance costs were recovered through Rate RSE. Customer rates were not impacted by this order in 2015; therefore, the modification increased the under recovered position for Rate CNP Compliance during 2015. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital.

On November 30, 2015, the Company made its annual Rate CNP Compliance submission to the Alabama PSC of its cost of complying with governmental mandates for cost year 2016. Rate CNP Compliance increased 4.5%, or approximately $250 million annually, effective January 1, 2016.

Rate ECR

The Company has established energy cost recovery rates under the Company's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH.

On December 1, 2015, the Alabama PSC approved a decrease in the Company’s Rate ECR factor from 2.681 to 2.030 cents per KWH, 6.7%, or $370 million annually, based upon projected billings, effective January 1, 2016. The approved decrease in the Rate ECR factor will have no significant effect on the Company's net income, but will decrease operating cash flows related to fuel cost recovery in 2016 when compared to 2015. The rate will return to 2.681 cents per KWH in 2017 and 5.910 cents per KWH in 2018, absent a further order from the Alabama PSC.

Environmental Accounting Order

Based on an order from the Alabama PSC, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. These costs are being amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through

Rate CNP Compliance. See "Environmental Matters – Environmental Statutes and Regulations" herein for additional information regarding environmental regulations.

In April 2015, as part of its environmental compliance strategy, the Company retired Plant Gorgas Units 6 and 7 (200 MWs). Additionally, in April 2015, the Company ceased using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. In accordance with the joint stipulation entered in connection with a civil enforcement action by the EPA, the Company retired Plant Barry Unit 3 (225 MWs) in August 2015 and it is no longer available for generation. The Company expects to cease using coal at Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas by April 2016.

In accordance with this accounting order from the Alabama PSC, the Company transferred the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized and recovered through Rate CNP Compliance over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on the Company's financial statements.

Renewables

On September 16, 2015, the Alabama PSC approved the Company's petition for a Renewable Generation Certificate for up to 500 MWs. This will allow the Company to build its own renewable projects, each less than 80 MWs, or purchase power from other renewable-generated sources.

Cost of Removal Accounting Order

In accordance with an accounting order issued in November 2014 by the Alabama PSC, in December 2014, the Company fully amortized the balance of $123 million in certain regulatory asset accounts and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset accounts fully amortized and terminated as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, which were approved by the Alabama PSC in 2012 and 2013, respectively. Approximately $95 million of non-nuclear outage costs and $28 million of compliance and pension costs previously deferred were fully amortized in December 2014.

Income Tax Matters

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 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 50% bonus depreciation is expected to result in approximately $220 million of positive cash flows for the 2015 tax year and approximately $240 million for the 2016 tax year.

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded pension costs of $48 million in 2015, $23 million in 2014 and $47 million in 2013. Postretirement benefit costs for the Company were $5 million, $4 million, and $7 million in 2015, 2014, and 2013, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

The Company is subject to retail regulation by the Alabama PSC and wholesale regulation by the FERC. 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, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

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 the decommissioning of the Company's nuclear facility, Plant Farley, and 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, asbestos removal, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. 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.

As a result of the final CCR Rule discussed above, the Company recorded new AROs for facilities that are subject to the CCR Rule. The cost estimates 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 in place. 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, 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.

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" and "Nuclear Decommissioning" 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 has 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 will decrease by approximately $24 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 $7 million or less change in total annual benefit expense and a $98 million or less change in projected obligations.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers,* revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances in long-term debt totaling $39 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 10 to the financial statements for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07) , effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the Company. See Notes 2 and 10 to the financial statements for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid expenses of $20 million and accrued income tax of $2 million to non-current accumulated deferred income taxes in the Company’s December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 to the financial statements for disclosures impacted by ASU 2015-17.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2015. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to comply with environmental regulations and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2016 through 2018, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to maintain existing generation facilities, to add environmental modifications to existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances, preferred and preference stock issuances, or parent company capital contributions. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds decreased in value as of December 31, 2015 as compared to December 31, 2014. No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated during 2016 . The Company's funding obligations for the nuclear decommissioning trust fund are based on the site study, and the next study is expected to be conducted in 2018. See Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $2.1 billion for 2015, an increase of $433 million as compared to 2014. The increase in cash provided from operating activities was primarily due to the timing of income tax payments and refunds associated with bonus depreciation, collection of fuel cost recovery revenues, partially offset by the timing of payment of accounts payable. Net cash provided from operating activities totaled $1.7 billion for 2014, a decrease of $205 million as compared to 2013. The decrease in cash provided from operating activities was primarily due to an increase in income tax payments and the timing of fossil fuel stock purchases, partially offset by the timing of payment of accounts payable.

Net cash used for investing activities totaled $1.5 billion for 2015, $1.6 billion for 2014, and $1.1 billion for 2013. In 2015, these activities were primarily related to gross property additions for environmental, distribution, steam generation, and transmission assets. In 2014, these activities were primarily related to gross property additions for environmental, distribution, transmission, steam generation, and nuclear fuel assets. In 2013, these activities were primarily related to gross property additions for steam generation, distribution, and transmission assets.

Net cash used for financing activities totaled $733 million in 2015 primarily due to the payment of common stock dividends and redemptions of securities, partially offset by issuances of long-term debt. Net cash used for financing activities totaled $164 million in 2014 primarily due to the payment of common stock dividends and issuances and redemptions of securities.

Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for 2015 included an increase of $1.3 billion in property, plant, and equipment primarily due to additions to steam generation, environmental, distribution, and transmission facilities including $619 million in AROs associated with the CCR Rule. Other significant changes include an increase of $384 million in accumulated deferred income taxes primarily as a result of bonus depreciation and an increase of $263 million in long term debt, including debt due within one year, primarily due to the issuance of additional senior notes. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Nuclear Decommissioning" and Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

The Company's ratio of common equity to total capitalization, including short-term debt, was 45.6% and 44.2% at December 31, 2015 and 2014, respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds to meet its future capital needs through operating cash flows, short-term debt, term loans, external security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, depend upon prevailing market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

The Company's current liabilities sometimes exceed current assets because of the Company's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At December 31, 2015, the Company had approximately $194 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2015 were as follows:

Expires					Due Within One Year	
2016	**2018**	**2020**	**Total**	**Unused**	**Term Out**	**No Term Out**
	(in millions)		*(in millions)*		*(in millions)*	
$ 40	$ 500	$ 800	$ 1,340	$ 1,340	$ —	$ 40

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

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross acceleration provisions to other indebtedness (including guarantee obligations) of the Company. 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. The Company is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

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 unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper borrowings. As of December 31, 2015, the Company had $810 million of outstanding variable rate pollution control revenue bonds requiring liquidity support. In addition, at December 31, 2015, the Company had $80 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs. The Company may meet short-term cash needs through its commercial paper program. The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2015:					
Commercial paper	**$ —**	**—%**	**$ 14**	**0.2%**	**$ 100**
December 31, 2014:					
Commercial paper	$ —	—%	$ 13	0.2%	$ 300
December 31, 2013:					
Commercial paper	$ —	—%	$ 11	0.2%	$ 90

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2015, 2014, and 2013.

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

Financing Activities

In March 2015, the Company issued $550 million aggregate principal amount of Series 2015A 3.750% Senior Notes due March 1, 2045. The proceeds were used to redeem $250 million aggregate principal amount of Series DD 5.65% Senior Notes due March 15, 2035 and for general corporate purposes, including the Company's continuous construction program.

In April 2015, the Company purchased and held $80 million aggregate principal amount of Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Bonds (Alabama Power Company Barry Plant Project), Series 2007-B. The Company reoffered these bonds to the public in May 2015.

Also in April 2015, the Company issued $175 million additional aggregate principal amount of its Series 2015A 3.750% Senior Notes due March 1, 2045 (Additional Series 2015A Senior Notes) and $250 million aggregate principal amount of its Series 2015B 2.800% Senior Notes due April 1, 2025 (Series 2015B Senior Notes). A portion of the proceeds of the Additional Series 2015A Senior Notes and the Series 2015B Senior Notes were used in May 2015 to redeem 6.48 million shares ($162 million aggregate stated capital) of the Company's 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, 4.0 million shares ($100 million aggregate stated capital) of the Company's 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and 6.0 million shares ($150 million aggregate stated capital) of the Company's 5.625% Series Preference Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and the remaining net proceeds were used for general corporate purposes, including the Company's continuous construction program.

In June 2015, $18.7 million aggregate principal amount of the Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 1994, $6.15 million aggregate principal amount of the Industrial Development Board of the City of Gadsden, Pollution Control Revenue Bonds (Alabama Power Company Project), Series 1994, and $28.85 million aggregate principal amount of the Industrial Development Board of the Town of Parrish, Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 1994A were repaid at maturity.

In October 2015, the Company repaid at maturity $400 million aggregate principal amount of its Series 2012B 0.550% Senior Notes due October 15, 2015.

Subsequent to December 31, 2015, the Company issued $400 million aggregate principal amount of Series 2016A 4.30% Senior Notes due January 2, 2046. The proceeds were used to repay at maturity $200 million aggregate principal amount of the

Company's Series FF 5.20% Senior Notes due January 15, 2016 and for general purposes, including the Company's continuous construction program.

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

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, energy price risk management, and transmission. The maximum potential collateral requirements under these contracts at December 31, 2015 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements	
	(in millions)	
At BBB and/or Baa2	$	1
At BBB- and/or Baa3	$	2
Below BBB- and/or Baa3	$	350

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, 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 August 17, 2015, S&P downgraded the consolidated long-term issuer rating of Southern Company (including the Company) to A- from A. S&P revised its credit rating outlook from negative to stable. Separately, on August 24, 2015, S&P revised its credit rating outlook from stable to negative following the announcement of the proposed merger of a wholly-owned direct subsidiary of Southern Company with and into AGL Resources Inc.

Market Price Risk

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

To mitigate 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 financial hedge contracts for natural gas purchases. The Company continues to manage a retail fuel-hedging program implemented per the guidelines of the Alabama PSC. The Company had no material change in market risk exposure for the year ended December 31, 2015 when compared to the year ended December 31, 2014.

In addition, Rate ECR allows the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at the Company's electric generating facilities. Rate ECR also allows recovery of the cost of financial instruments used for hedging market price risk up to 75% of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5% of the Company's natural gas budget for that year.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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:

	2015 Changes	2014 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (52)**	$ (1)
Contracts realized or settled	**41**	(7)
Current period changes (*)	**(43)**	(44)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (54)**	$ (52)

(*) 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, for the years ended December 31 were as follows:

	2015	2014
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**44**	54
Commodity – Natural gas options	**6**	2
Total hedge volume	**50**	56

The weighted average swap contract cost above market prices was approximately $1.13 per mmBtu as of December 31, 2015 and $0.89 per mmBtu as of December 31, 2014. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the Company's retail energy cost recovery clause.

At December 31, 2015 and 2014, 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 energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 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, 2015 were as follows:

	Fair Value Measurements December 31, 2015		
	Total Fair Value	Maturity Year 1	Maturity Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(54)	(39)	(15)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (54)	$ (39)	$ (15)

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's 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 11 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $1.3 billion per year for 2016, 2017, and 2018. The construction program includes capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.3 billion per year for 2016, 2017, and 2018. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure in place and ground water monitoring of ash ponds in accordance with the CCR Rule, which are not reflected in the capital expenditures above as these costs are associated with 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, are estimated to be $20 million, $20 million, and $66 million for the years 2016, 2017, and 2018 respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information. Costs associated with the CCR Rule are expected to be recovered through Rate CNP Compliance.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; 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 the expected environmental compliance program; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of NRC requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, 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 Alabama PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, pension and other postretirement benefit plans, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

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Contractual Obligations

	2016	2017-2018	2019-2020	After 2020	Total
			(in millions)		
Long-term debt [(a)] —					
Principal	$ 200	$ 561	$ 450	$ 5,692	$ 6,903
Interest	275	500	461	3,706	4,942
Preferred and preference stock dividends [(b)]	17	34	34	—	85
Financial derivative obligations [(c)]	54	16	—	—	70
Operating leases [(d)]	19	22	18	13	72
Capital Lease	—	1	1	3	5
Purchase commitments —					
Capital [(e)]	1,210	2,370	—	—	3,580
Fuel [(f)]	1,108	1,638	886	261	3,893
Purchased power [(g)]	78	167	182	803	1,230
Other [(h)]	40	83	67	335	525
Pension and other postretirement benefit plans [(i)]	20	38	—	—	58
Total	$ 3,021	$ 5,430	$ 2,099	$ 10,813	$ 21,363

(a) All amounts are reflected based on final maturity dates. 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, 2016, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

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

(c) Includes derivative liabilities related to cash flow hedges of forecasted debt, as well as energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.

(d) Excludes PPAs that are accounted for as leases and are included in purchased power.

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected in "Fuel" and "Other," respectively. At December 31, 2015 , significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

(f) Includes commitments to purchase coal, nuclear fuel, 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, 2015.

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy. Amounts are related to the Company's certificated PPAs which include MWs purchased from gas-fired and wind-powered facilities.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

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

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2015 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, 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 , postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of changing fuel sources, filings with state and federal regulatory authorities, impact of the PATH Act, estimated sales and purchases under power sale and purchase agreements, 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 legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, 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, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including , without limitation, IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the 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 and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards ;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the inherent risks involved in operating nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- 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 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.

STATEMENTS OF INCOME
For the Years Ended December 31, 2015 , 2014 , and 2013
Alabama Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 5,234**	$ 5,249	$ 4,952
Wholesale revenues, non-affiliates	**241**	281	248
Wholesale revenues, affiliates	**84**	189	212
Other revenues	**209**	223	206
Total operating revenues	**5,768**	5,942	5,618
Operating Expenses:			
Fuel	**1,342**	1,605	1,631
Purchased power, non-affiliates	**171**	185	100
Purchased power, affiliates	**180**	200	129
Other operations and maintenance	**1,501**	1,468	1,289
Depreciation and amortization	**643**	603	645
Taxes other than income taxes	**368**	356	348
Total operating expenses	**4,205**	4,417	4,142
Operating Income	**1,563**	1,525	1,476
Other Income and (Expense):			
Allowance for equity funds used during construction	**60**	49	32
Interest income	**15**	15	16
Interest expense, net of amounts capitalized	**(274)**	(255)	(259)
Other income (expense), net	**(47)**	(22)	(36)
Total other income and (expense)	**(246)**	(213)	(247)
Earnings Before Income Taxes	**1,317**	1,312	1,229
Income taxes	**506**	512	478
Net Income	**811**	800	751
Dividends on Preferred and Preference Stock	**26**	39	39
Net Income After Dividends on Preferred and Preference Stock	**$ 785**	$ 761	$ 712

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2015 , 2014 , and 2013
Alabama Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Net Income	**$ 811**	$ 800	$ 751
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(3), $(3), and $-, respectively	**(5)**	(5)	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**2**	2	1
Total other comprehensive income (loss)	**(3)**	(3)	1
Comprehensive Income	**$ 808**	$ 797	$ 752

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2015 , 2014 , and 2013
Alabama Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Activities:			
Net income	**$ 811**	$ 800	$ 751
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**780**	724	816
Deferred income taxes	**388**	270	198
Allowance for equity funds used during construction	**(60)**	(49)	(32)
Pension, postretirement, and other employee benefits	**20**	(61)	9
Stock based compensation expense	**15**	11	10
Other, net	**(20)**	17	(38)
Changes in certain current assets and liabilities —			
-Receivables	**(160)**	(58)	2
-Fossil fuel stock	**28**	61	146
-Materials and supplies	**15**	(17)	19
-Other current assets	**(3)**	(11)	5
-Accounts payable	**3**	157	35
-Accrued taxes	**138**	(199)	(23)
-Accrued compensation	**(16)**	50	(23)
-Retail fuel cost over recovery	**191**	5	42
-Other current liabilities	**12**	9	(3)
Net cash provided from operating activities	**2,142**	1,709	1,914
Investing Activities:			
Property additions	**(1,367)**	(1,457)	(1,107)
Nuclear decommissioning trust fund purchases	**(439)**	(245)	(280)
Nuclear decommissioning trust fund sales	**438**	244	279
Cost of removal net of salvage	**(71)**	(77)	(47)
Change in construction payables	**(15)**	(10)	(13)
Other investing activities	**(34)**	(22)	26
Net cash used for investing activities	**(1,488)**	(1,567)	(1,142)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	**22**	28	24
Pollution control revenue bonds	**80**	254	—
Senior notes issuances	**975**	400	300
Redemptions and repurchases —			
Preferred and preference stock	**(412)**	—	—
Pollution control revenue bonds	**(134)**	(254)	—
Senior notes	**(650)**	—	(250)
Payment of preferred and preference stock dividends	**(31)**	(39)	(39)
Payment of common stock dividends	**(571)**	(550)	(644)
Other financing activities	**(12)**	(3)	(5)
Net cash used for financing activities	**(733)**	(164)	(614)
Net Change in Cash and Cash Equivalents	**(79)**	(22)	158
Cash and Cash Equivalents at Beginning of Year	**273**	295	137
Cash and Cash Equivalents at End of Year	**$ 194**	$ 273	$ 295
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $22, $18, and $11 capitalized, respectively)	**$ 250**	$ 231	$ 243

Income taxes (net of refunds)	**121**	436	296
Noncash transactions — accrued property additions at year-end	**121**	8	18

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

BALANCE SHEETS
At December 31, 2015 and 2014
Alabama Power Company 2015 Annual Report

Assets	2015	2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 194	$ 273
Receivables —		
Customer accounts receivable	332	345
Unbilled revenues	119	138
Under recovered regulatory clause revenues	43	74
Other accounts and notes receivable	20	23
Affiliated companies	50	37
Accumulated provision for uncollectible accounts	(10)	(9)
Income taxes receivable, current	142	—
Fossil fuel stock, at average cost	239	268
Materials and supplies, at average cost	398	406
Vacation pay	66	65
Prepaid expenses	83	224
Other regulatory assets, current	115	84
Other current assets	10	6
Total current assets	1,801	1,934
Property, Plant, and Equipment:		
In service	24,750	23,080
Less accumulated provision for depreciation	8,736	8,522
Plant in service, net of depreciation	16,014	14,558
Nuclear fuel, at amortized cost	363	348
Construction work in progress	801	1,006
Total property, plant, and equipment	17,178	15,912
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	71	66
Nuclear decommissioning trusts, at fair value	737	756
Miscellaneous property and investments	96	84
Total other property and investments	904	906
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	522	525
Deferred under recovered regulatory clause revenues	99	31
Other regulatory assets, deferred	1,114	1,063
Other deferred charges and assets	103	122
Total deferred charges and other assets	1,838	1,741
Total Assets	$ 21,721	$ 20,493

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

BALANCE SHEETS
At December 31, 2015 and 2014
Alabama Power Company 2015 Annual Report

Liabilities and Stockholder's Equity		**2015**		2014
		(in millions)		
Current Liabilities:				
Securities due within one year	**$**	**200**	$	454
Accounts payable —				
Affiliated		**278**		248
Other		**410**		443
Customer deposits		**88**		87
Accrued taxes		**38**		37
Accrued interest		**73**		66
Accrued vacation pay		**55**		54
Accrued compensation		**119**		131
Liabilities from risk management activities		**55**		40
Other regulatory liabilities, current		**240**		2
Other current liabilities		**39**		40
Total current liabilities		**1,595**		1,602
Long-Term Debt (See accompanying statements)		**6,654**		6,137
Deferred Credits and Other Liabilities:				
Accumulated deferred income taxes		**4,241**		3,857
Deferred credits related to income taxes		**70**		72
Accumulated deferred investment tax credits		**118**		125
Employee benefit obligations		**388**		326
Asset retirement obligations		**1,448**		829
Other cost of removal obligations		**722**		744
Other regulatory liabilities, deferred		**136**		239
Deferred over recovered regulatory clause revenues		**—**		47
Other deferred credits and liabilities		**76**		78
Total deferred credits and other liabilities		**7,199**		6,317
Total Liabilities		**15,448**		14,056
Redeemable Preferred Stock (See accompanying statements)		**85**		342
Preference Stock (See accompanying statements)		**196**		343
Common Stockholder's Equity (See accompanying statements)		**5,992**		5,752
Total Liabilities and Stockholder's Equity	**$**	**21,721**	$	20,493
Commitments and Contingent Matters (See notes)				

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

STATEMENTS OF CAPITALIZATION
At December 31, 2015 and 2014
Alabama Power Company 2015 Annual Report

	2015	2014	**2015**	2014
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (3.43% at 1/1/16) due 2042	$ **206**	$ 206		
Long-term notes payable —				
0.55% due 2015	—	400		
5.20% due 2016	**200**	200		
5.50% to 5.55% due 2017	**525**	525		
5.125% due 2019	**200**	200		
3.375% due 2020	**250**	250		
2.80% to 6.125% due 2021-2045	**4,425**	3,700		
Total long-term notes payable	**5,600**	5,275		
Other long-term debt —				
Pollution control revenue bonds —				
0.28% to 5.00% due 2034	**287**	367		
Variable rate (0.03% at 1/1/15) due 2015	—	54		
Variable rates (0.05% to 0.06% at 1/1/16) due 2017	**36**	36		
Variable rates (0.01% to 0.09% at 1/1/16) due 2021-2038	**774**	694		
Total other long-term debt	**1,097**	1,151		
Capitalized lease obligations	**5**	5		
Unamortized debt premium (discount), net	**(9)**	(7)		
Unamortized debt issuance expense	**(45)**	(39)		
Total long-term debt (annual interest requirement — $275 million)	**6,854**	6,591		
Less amount due within one year	**200**	454		
Long-term debt excluding amount due within one year	**6,654**	6,137	**51.4%**	48.8%
Redeemable Preferred Stock:				
Cumulative redeemable preferred stock				
$100 par or stated value — 4.20% to 4.92%				
Authorized — 3,850,000 shares				
Outstanding — 475,115 shares	**48**	48		
$1 par value —				
Authorized — 27,500,000 shares				
Outstanding — $25 stated value				
— 2015: 5.83% — 1,520,000 shares				
— 2014: 5.20% to 5.83% — 12,000,000 shares				
(annual dividend requirement — $4 million)	**37**	294		
Total redeemable preferred stock	**85**	342	**0.7**	2.7
Preference Stock:				
Authorized — 40,000,000 shares				
Outstanding — $1 par value — $25 stated value				
— 2015: 6.45% to 6.50% — 8,000,000 shares (non-cumulative)				
— 2014: 5.63% to 6.50% — 14,000,000 shares (non-cumulative)				
(annual dividend requirement — $13 million)	**196**	343	**1.5**	2.7
Common Stockholder's Equity:				
Common stock, par value $40 per share —				
Authorized — 40,000,000 shares				
Outstanding — 30,537,500 shares	**1,222**	1,222		
Paid-in capital	**2,341**	2,304		

Retained earnings		**2,461**		2,255		
Accumulated other comprehensive loss		**(32)**		(29)		
Total common stockholder's equity		**5,992**		5,752	**46.4**	45.8
Total Capitalization	**$**	**12,927**	$	12,574	**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, 2015 , 2014 , and 2013
Alabama Power Company 2015 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2012	31	$ 1,222	$ 2,227	$ 1,976	$ (27)	$ 5,398
Net income after dividends on preferred and preference stock	—	—	—	712	—	712
Capital contributions from parent company	—	—	35	—	—	35
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(644)	—	(644)
Balance at December 31, 2013	31	1,222	2,262	2,044	(26)	5,502
Net income after dividends on preferred and preference stock	—	—	—	761	—	761
Capital contributions from parent company	—	—	42	—	—	42
Other comprehensive income (loss)	—	—	—	—	(3)	(3)
Cash dividends on common stock	—	—	—	(550)	—	(550)
Balance at December 31, 2014	**31**	**1,222**	**2,304**	**2,255**	**(29)**	**5,752**
Net income after dividends on preferred and preference stock	—	—	—	**785**	—	**785**
Capital contributions from parent company	—	—	**37**	—	—	**37**
Other comprehensive income (loss)	—	—	—	—	**(3)**	**(3)**
Cash dividends on common stock	—	—	—	**(571)**	—	**(571)**
Other	—	—	—	**(8)**	—	**(8)**
Balance at December 31, 2015	**31**	**$ 1,222**	**$ 2,341**	**$ 2,461**	**$ (32)**	**$ 5,992**

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

NOTES TO FINANCIAL STATEMENTS
Alabama Power Company 2015 Annual Report

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – the Company, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electricity to retail and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Farley.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the FERC and the Alabama 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

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers,* revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances in long-term debt totaling $39 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 10 for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07) , effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the Company. See Notes 2 and 10 for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid expenses of $20 million and accrued income tax of $2 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 for disclosures impacted by ASU 2015-17.

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 $438 million , $400 million , and $340 million during 2015 , 2014 , and 2013 , 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 Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $243 million , $234 million , and $211 million during 2015 , 2014 , and 2013 , respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses, which were $11 million in 2015 , $13 million in 2014 , and $13 million in 2013 . Also, Mississippi Power reimburses the Company for any direct fuel purchases delivered from one of the Company's transfer facilities, which were $8 million in 2015, $34 million in 2014, and $27 million in 2013. See Note 4 for additional information.

The Company has an agreement with Gulf Power under which the Company has made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA from a combined cycle plant located in Autauga County, Alabama. The transmission improvements were completed in 2014. The Company received $14 million in 2015 and expects to recover approximately $12 million a year from 2016 through 2023 through a tariff with Gulf Power.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2015 , 2014 , or 2013 .

Also, see Note 4 for information regarding the Company's ownership in a PPA and a gas pipeline ownership agreement with SEGCO.

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

Regulatory Assets and Liabilities

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

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

	2015	2014	Note
	(in millions)		
Deferred income tax charges	**$ 522**	$ 525	(a,k)
Loss on reacquired debt	**75**	80	(b)
Vacation pay	**66**	65	(c,j)
Under/(over) recovered regulatory clause revenues	**(97)**	57	(d)
Fuel-hedging losses	**55**	53	(e,j)
Other regulatory assets	**53**	49	(f)
Asset retirement obligations	**(40)**	(125)	(a)
Other cost of removal obligations	**(722)**	(744)	(a)
Deferred income tax credits	**(70)**	(72)	(a)
Nuclear outage	**53**	56	(d)
Natural disaster reserve	**(75)**	(84)	(h)
Other regulatory liabilities	**(8)**	(17)	(e,g)
Retiree benefit plans	**903**	882	(i,j)
Remaining net book value of retired assets	**76**	13	(l)
Total regulatory assets (liabilities), net	**$ 791**	$ 738	

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

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

(b) Recovered over the remaining life of the original issue, which may range up to 50 years .

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

(d) Recorded and recovered or amortized as approved or accepted by the Alabama PSC over periods not exceeding 10 years .

(e) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three and a half years . Upon final settlement, actual costs incurred are recovered through the energy cost recovery clause.

(f) Comprised of components including generation site selection/evaluation costs, PPA capacity, and other miscellaneous assets. Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.

(g) Comprised of components including mine reclamation and remediation liabilities, fuel-hedging gains and nuclear fuel disposal fee. Recorded as accepted by the Alabama PSC. Mine reclamation and remediation liabilities will be settled following completion of the related activities. Nuclear fuel disposal fees are recorded as approved by the Alabama PSC related to potential future fees for nuclear waste disposal. The balance was transferred to Rate ECR in 2015. See Note 3 for additional information.

(h) Utilized as storm restoration and potential reliability-related expenses are incurred, as approved by the Alabama PSC.

(i) Recovered and amortized over the average remaining service period which may range up to 15 years . See Note 2 for additional information.

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

(k) Included in the deferred income tax charges are $17 million for 2015 and $18 million for 2014 for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Alabama PSC, over the average remaining service period which may range up to 15 years .

(l) Recorded and amortized as approved by the Alabama PSC for a period up to 11 years .

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off 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" for additional information.

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters – Rate ECR" and "Retail Regulatory Matters – Rate CNP" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel.

See Note 3 under "Retail Regulatory Matters – Nuclear Waste Fund Fee Accounting Order" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Federal ITCs utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

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.

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

	2015	2014
	(in millions)	
Generation	**$ 12,820**	$ 11,670
Transmission	**3,773**	3,579
Distribution	**6,432**	6,196
General	**1,713**	1,623
Plant acquisition adjustment	**12**	12
Total plant in service	**$ 24,750**	$ 23,080

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 as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders.

Nuclear Outage Accounting Order

In accordance with an Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over a subsequent 18 -month period with the fall outage costs amortization beginning in January of the following year and the spring outage costs amortization beginning in July of the same year.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.9% in 2015 , 3.3% in 2014 and 3.2% in 2013 . Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC and approved by the FERC. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2014, the Company submitted a depreciation study to the FERC and received authorization to use the recommended rates beginning January 2015. The study was also provided to the Alabama PSC. The new rates resulted in the decrease in the composite depreciation rate for 2015.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) 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 Alabama PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to the decommissioning of the Company's nuclear facility, Plant Farley, and facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA on April 17, 2015 (CCR Rule), principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. 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 Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

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

	2015	2014
	(in millions)	
Balance at beginning of year	**$ 829**	$ 730
Liabilities incurred	**402**	1
Liabilities settled	**(3)**	(3)
Accretion	**53**	45
Cash flow revisions	**167**	56
Balance at end of year	**$ 1,448**	$ 829

The increase in liabilities incurred and cash flow revisions in 2015 is primarily related to the Company's AROs associated with the impact of the CCR Rule on its ash and gypsum facilities. The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2015 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 in place. 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, 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.

The cash flow revisions in 2014 are primarily related to the Company's AROs associated with asbestos at its steam generation facilities.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Alabama PSC, as well as the IRS. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

At December 31, 2015 , investment securities in the Funds totaled $734 million , consisting of equity securities of $521 million , debt securities of $191 million , and $22 million of other securities. At December 31, 2014 , investment securities in the Funds totaled $754 million , consisting of equity securities of $583 million , debt securities of $163 million , and $8 million of other securities. These amounts exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases.

Sales of the securities held in the Funds resulted in cash proceeds of $438 million , $244 million , and $279 million in 2015 , 2014 , and 2013 , respectively, all of which were reinvested. For 2015 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $8 million , which included $57 million related to unrealized losses on securities held in the Funds at December 31, 2015 . For 2014 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $54 million , which included $19 million related to unrealized gains on securities held in the Funds at December 31, 2014 . For 2013 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $120 million , which included $85 million related to unrealized losses on securities held in the Funds at December 31, 2013 . While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the Funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed a plan with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, the accumulated provisions for decommissioning were as follows:

	2015	2014
	(in millions)	
External trust funds	**$ 734**	$ 754
Internal reserves	**20**	21
Total	**$ 754**	$ 775

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Site study costs is the estimate to decommission a facility as of the site study year. The estimated costs of decommissioning as of December 31, 2015 based on the most current study performed in 2013 for Plant Farley are as follows:

Decommissioning periods:	
Beginning year	2037
Completion year	2076

	(in millions)
Site study costs:	
Radiated structures	$ 1,362
Non-radiated structures	80
Total site study costs	$ 1,442

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, the Company's decommissioning costs are based on the site study. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and a trust earnings rate of 7.0% . The next site study is expected to be conducted in 2018.

Amounts previously contributed to the Funds are currently projected to be adequate to meet the decommissioning obligations. The Company will continue to provide site-specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with NRC and other applicable requirements.

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 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 calculating taxable income. All current construction costs are included in retail rates. The AFUDC composite rate as of December 31 was 8.7% in 2015 , 8.8% in 2014 , and 9.1% in 2013 . AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 9.3% in 2015 , 7.9% in 2014 , and 5.4% in 2013 .

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.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through energy cost recovery rates approved by the Alabama PSC. 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, and electricity purchases and sales. 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 10 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 fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Alabama PSC-approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. If any, immaterial ineffectiveness arising from cash flow hedges is recognized currently in net income. 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 income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2015 .

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 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 has established a wholly-owned trust to issue preferred securities. See Note 6 under "Long-Term Debt Payable to an Affiliated Trust" for additional information. However, the Company is not considered the primary beneficiary of the trust. Therefore, the investment in the trust is reflected as other investments, and the related loan from the trust is reflected as long-term debt in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2016 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2016 , no other postretirement trusts 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:	2015	2014	2013
Pension plans			
Discount rate – interest costs	**4.18%**	5.02%	4.27%
Discount rate – service costs	**4.49**	5.02	4.27
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**3.59**	3.59	3.59
Other postretirement benefit plans			
Discount rate – interest costs	**4.04%**	4.86%	4.06%
Discount rate – service costs	**4.40**	4.86	4.06
Expected long-term return on plan assets	**7.17**	7.34	7.36
Annual salary increase	**3.59**	3.59	3.59

Assumptions used to determine benefit obligations:	2015	2014
Pension plans		
Discount rate	**4.67%**	4.18%
Annual salary increase	**4.46**	3.59
Other postretirement benefit plans		
Discount rate	**4.51%**	4.04%
Annual salary increase	**4.46**	3.59

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

For purposes of its December 31, 2015 measurement date, the Company adopted new mortality tables for its pension and other postretirement benefit plans, which reflect decreased life expectancies in the U.S. The adoption of new mortality tables reduced the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $51 million and $9 million , respectively.

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, 2015 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2024
Post-65 medical	5.50	4.50	2024
Post-65 prescription	10.00	4.50	2025

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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, 2015 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 29	$ (25)
Service and interest costs	1	(1)

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.3 billion at December 31, 2015 and $2.4 billion at December 31, 2014 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,592**	$ 2,112
Service cost	**59**	48
Interest cost	**106**	103
Benefits paid	**(120)**	(100)
Actuarial loss (gain)	**(131)**	429
Balance at end of year	**2,506**	2,592
Change in plan assets		
Fair value of plan assets at beginning of year	**2,396**	2,278
Actual return (loss) on plan assets	**(9)**	207
Employer contributions	**12**	11
Benefits paid	**(120)**	(100)
Fair value of plan assets at end of year	**2,279**	2,396
Accrued liability	**$ (227)**	$ (196)

At December 31, 2015 , the projected benefit obligations for the qualified and non-qualified pension plans were $2.4 billion and $124 million , respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's pension plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 822**	$ 827
Other current liabilities	**(11)**	(10)
Employee benefit obligations	**(216)**	(186)

Presented below are the amounts included in regulatory assets at December 31, 2015 and 2014 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 2016 .

	2015	2014	Estimated Amortization in 2016
		(in millions)	
Prior service cost	$ 6	$ 12	$ 3
Net (gain) loss	816	815	40
Regulatory assets	$ 822	$ 827	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Regulatory assets:		
Beginning balance	$ 827	$ 476
Net (gain) loss	56	389
Reclassification adjustments:		
Amortization of prior service costs	(6)	(7)
Amortization of net gain (loss)	(55)	(31)
Total reclassification adjustments	(61)	(38)
Total change	(5)	351
Ending balance	$ 822	$ 827

Components of net periodic pension cost were as follows:

	2015	2014	2013
		(in millions)	
Service cost	$ 59	$ 48	$ 52
Interest cost	106	103	93
Expected return on plan assets	(178)	(168)	(157)
Recognized net loss	55	31	52
Net amortization	6	7	7
Net periodic pension cost	$ 48	$ 21	$ 47

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, 2015 , estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2016	$ 114
2017	119
2018	124
2019	129
2020	134
2021 to 2025	740

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 503**	$ 431
Service cost	**6**	5
Interest cost	**20**	20
Benefits paid	**(27)**	(27)
Actuarial loss (gain)	**(7)**	71
Plan amendment	**7**	—
Retiree drug subsidy	**3**	3
Balance at end of year	**505**	503
Change in plan assets		
Fair value of plan assets at beginning of year	**392**	389
Actual return (loss) on plan assets	**(6)**	23
Employer contributions	**1**	4
Benefits paid	**(24)**	(24)
Fair value of plan assets at end of year	**363**	392
Accrued liability	**$ (142)**	$ (111)

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's other postretirement benefit plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 95**	$ 68
Other regulatory liabilities, deferred	**(13)**	(14)
Employee benefit obligations	**(142)**	(111)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2015 and 2014 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2016 .

	2015	2014	**Estimated Amortization in 2016**
		(in millions)	
Prior service cost	**$ 19**	$ 15	**$ 4**
Net (gain) loss	**63**	39	**2**
Net regulatory assets	**$ 82**	$ 54	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	**$ 54**	$ (15)
Net (gain) loss	**25**	73
Change in prior service costs	**8**	—
Reclassification adjustments:		
Amortization of prior service costs	**(3)**	(4)
Amortization of net gain (loss)	**(2)**	—
Total reclassification adjustments	**(5)**	(4)
Total change	**28**	69
Ending balance	**$ 82**	$ 54

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

	2015	2014	2013
		(in millions)	
Service cost	**$ 6**	$ 5	$ 6
Interest cost	**20**	20	19
Expected return on plan assets	**(26)**	(25)	(23)
Net amortization	**5**	4	5
Net periodic postretirement benefit cost	**$ 5**	$ 4	$ 7

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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)	
2016	$ 33	$ (3)	$ 30
2017	34	(3)	31
2018	34	(3)	31
2019	35	(4)	31
2020	36	(4)	32
2021 to 2025	184	(20)	164

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. 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, 2015 and 2014 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2015**	2014
Pension plan assets:			
Domestic equity	26%	**30%**	30%
International equity	25	**23**	23
Fixed income	23	**23**	27
Special situations	3	**2**	1
Real estate investments	14	**16**	14
Private equity	9	**6**	5
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	48%	**45%**	48%
International equity	20	**20**	20
Domestic fixed income	24	**27**	26
Special situations	1	**1**	—
Real estate investments	4	**5**	4
Private equity	3	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns 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.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***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, 2015 and 2014 . 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.
- ***TOLI.*** Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

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The fair values of pension plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 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*	$ 403	$ 168	$ —	$ —	$ 571
International equity*	294	244	—	—	538
Fixed income:					
U.S. Treasury, government, and agency bonds	—	112	—	—	112
Mortgage- and asset-backed securities	—	49	—	—	49
Corporate bonds	—	280	—	—	280
Pooled funds	—	123	—	—	123
Cash equivalents and other	—	36	—	—	36
Real estate investments	74	—	—	301	375
Private equity	—	—	—	157	157
Total	$ 771	$ 1,012	$ —	$ 458	$ 2,241

* 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.

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As of December 31, 2014:	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*	$ 421	$ 174	$ —	$ —	$ 595
International equity*	264	244	—	—	508
Fixed income:					
U.S. Treasury, government, and agency bonds	—	173	—	—	173
Mortgage- and asset-backed securities	—	47	—	—	47
Corporate bonds	—	280	—	—	280
Pooled funds	—	127	—	—	127
Cash equivalents and other	1	163	—	—	164
Real estate investments	73	—	—	277	350
Private equity	—	—	—	141	141
Total	$ 759	$ 1,208	$ —	$ 418	$ 2,385

* 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, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

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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*	$ 57	$ 8	$ —	$ —	$ 65
International equity*	14	12	—	—	26
Fixed income:					
U.S. Treasury, government, and agency bonds	—	8	—	—	8
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	13	—	—	13
Pooled funds	—	6	—	—	6
Cash equivalents and other	1	2	—	—	3
Trust-owned life insurance	—	212	—	—	212
Real estate investments	5	—	—	14	19
Private equity	—	—	—	7	7
Total	$ 77	$ 263	$ —	$ 21	$ 361

* 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.

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As of December 31, 2014:	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	$ 8	$ —	$ —	$ 84
International equity*	13	12	—	—	25
Fixed income:					
U.S. Treasury, government, and agency bonds	—	10	—	—	10
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	14	—	—	14
Pooled funds	—	6	—	—	6
Cash equivalents and other	—	8	—	—	8
Trust-owned life insurance	—	217	—	—	217
Real estate investments	5	—	—	13	18
Private equity	—	—	—	7	7
Total	$ 94	$ 277	$ —	$ 20	$ 391

* 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 2015 , 2014 , and 2013 were $22 million , $21 million , and $20 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has 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 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 sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into a contract with the Company that requires the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Farley beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company has pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

In December 2014, the Court of Federal Claims entered a judgment in favor of the Company in its spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. On March 19, 2015, the Company recovered approximately $26 million . In November 2015, the Company applied the retail-related proceeds to offset the nuclear fuel expense under Rate ECR. See "Retail Regulatory Matters – Nuclear Waste Fund Accounting Order" herein for additional information. In December 2015, the Company credited the wholesale-related proceeds to each wholesale customer.

In March 2014, the Company filed an additional lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Farley for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2015 for any potential recoveries from this lawsuit. The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected.

At Plant Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of the plant.

FERC Matters

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 operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional 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 operating companies and in some adjacent areas. The FERC directed the traditional 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 operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon the Company's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Retail rates remain unchanged when the WCE ranges between 5.75% and 6.21% . Rate RSE adjustments for any two -year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0% . If the Company's actual retail return is above the allowed WCE range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

In 2013, the Alabama PSC approved a revision to Rate RSE, effective for calendar year 2014. This revision established the WCE range of 5.75% to 6.21% with an adjusting point of 5.98% and provided eligibility for a performance-based adder of seven basis points, or 0.07% , to the WCE adjusting point if the Company (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

The Rate RSE increase for 2015 was 3.49% or $181 million annually, and was effective January 1, 2015. On November 30, 2015, the Company made its annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2016. Projected earnings were within the specified WCE range; therefore, retail rates under Rate RSE remained unchanged for 2016.

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Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 3, 2015, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2015 through March 31, 2016. No adjustment to Rate CNP PPA is expected in 2016. As of December 31, 2015 , the Company had an under recovered certificated PPA balance of $99 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Rate CNP Environmental allowed for the recovery of the Company's retail costs associated with environmental laws, regulations, and other such mandates. On March 3, 2015, the Alabama PSC approved a modification to Rate CNP Environmental to include compliance costs for both environmental and non-environmental mandates. The recoverable non-environmental compliance costs result from laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. This modification to Rate CNP Environmental was effective March 20, 2015 with the revised rate now defined as Rate CNP Compliance. The Company was limited to recover $50 million of non-environmental compliance costs for the year 2015. Additional non-environmental compliance costs were recovered through Rate RSE. Customer rates were not impacted by this order in 2015; therefore, the modification increased the under recovered position for Rate CNP Compliance during 2015. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital.

Rate CNP Compliance increased 1.5% , or $75 million annually, effective January 1, 2015. As of December 31, 2015, the Company had an under recovered compliance clause balance of $43 million , which is included in under recovered regulatory clause revenues in the balance sheet.

Rate ECR

The Company has established energy cost recovery rates under the Company's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. In December 2014, the Alabama PSC issued a consent order that the Company leave in effect for 2015 the Rate ECR factor of 2.681 cents per KWH.

On December 1, 2015, the Alabama PSC approved a decrease in the Company’s Rate ECR factor from 2.681 to 2.030 cents per KWH, 6.7% , or $370 million annually, based upon projected billings, effective January 1, 2016. The approved decrease in the Rate ECR factor will have no significant effect on the Company's net income, but will decrease operating cash flows related to fuel cost recovery in 2016 when compared to 2015. The rate will return to 2.681 cents per KWH in 2017 and 5.910 cents per KWH in 2018, absent a further order from the Alabama PSC.

The Company's over recovered fuel costs at December 31, 2015 totaled $238 million as compared to $47 million at December 31, 2014. At December 31, 2015, $238 million is included in other regulatory liabilities, current. The over recovered fuel costs at December 31, 2014 are included in deferred over recovered regulatory clause revenues. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery or return of fuel costs.

Rate NDR

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24 -month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million . The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

Environmental Accounting Order

Based on an order from the Alabama PSC, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs, associated with site removal and closure associated with future unit retirements caused by environmental regulations. These costs are being amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance.

In April 2015, as part of its environmental compliance strategy, the Company retired Plant Gorgas Units 6 and 7 (200 MWs). Additionally, in April 2015, the Company ceased using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. In accordance with the joint stipulation entered in connection with a civil enforcement action by the EPA, the Company retired Plant Barry Unit 3 (225 MWs) in August 2015 and it is no longer available for generation. The Company expects to cease using coal at Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas by April 2016.

In accordance with this accounting order from the Alabama PSC, the Company transferred the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized and recovered through Rate CNP Compliance over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on the Company's financial statements.

Nuclear Waste Fund Accounting Order

In 2013, the U.S. District Court for the District of Columbia ordered the DOE to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the DOE either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. The DOE formally set the fee to zero effective May 16, 2014.

In August 2014, the Alabama PSC issued an order to provide for the continued recovery from customers of amounts associated with the permanent disposal of nuclear waste from the operation of Plant Farley. In accordance with the order, effective May 16, 2014, the Company was authorized to recover from customers an amount equal to the prior fee and to record the amounts in a regulatory liability account (approximately $14 million annually). On December 1, 2015, the Alabama PSC issued an order for the Company to discontinue recording the amounts recovered from customers in a regulatory liability account and transfer amounts recorded in the regulatory liability to Rate ECR. On December 1, 2015, the Company transferred $20 million from the regulatory liability to Rate ECR to offset fuel expense.

Cost of Removal Accounting Order

In accordance with an accounting order issued in November 2014 by the Alabama PSC, in December 2014, the Company fully amortized the balance of $123 million in certain regulatory asset accounts and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset accounts fully amortized and terminated as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, which were approved by the Alabama PSC in 2012 and 2013, respectively. Approximately $95 million of non-nuclear outage costs and $28 million of compliance and pension costs were fully amortized in December 2014.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and ROE. The Company's share of purchased power totaled $76 million in 2015 , $84 million in 2014 , and $88 million in 2013 and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

In addition, the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $25 million principal amount of pollution control revenue bonds are outstanding. The Company has guaranteed $100 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. These senior notes mature on December 1, 2018. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guarantee.

At December 31, 2015 , the capitalization of SEGCO consisted of $118 million of equity and $125 million of long-term debt on which the annual interest requirement is $3 million . In addition, SEGCO had short-term debt outstanding of $52 million . SEGCO paid an immaterial amount of dividends in 2015 compared to $3 million in 2014 and $7 million in 2013 , of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

SEGCO added natural gas as a fuel source for 1,000 MWs of its generating capacity in 2015. In April 2016, natural gas will become the primary fuel source. The Company, which owns and operates a generating unit adjacent to the SEGCO generating units, has entered into a joint ownership agreement with SEGCO for the ownership of the gas pipeline. The Company owns 14% of the pipeline with the remaining 86% owned by SEGCO.

In addition to the Company's ownership of SEGCO and joint ownership of the natural gas pipeline, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2015 were as follows:

Facility	**Total MW Capacity**	**Company Ownership**	**Plant in Service**	**Accumulated Depreciation**	**Construction Work in Progress**
				(in millions)	
Greene County	500	60.00% (1)	$ 159	$ 97	$ 20
Plant Miller					
Units 1 and 2	1,320	91.84% (2)	1,518	587	63

(1) Jointly owned with an affiliate, Mississippi Power.

(2) Jointly owned with PowerSouth Energy Cooperative, Inc.

The Company has contracted to operate and maintain the jointly-owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

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:

	2015	2014	2013
		(in millions)	
Federal —			
Current	$ 110	$ 198	$ 243
Deferred	320	225	160
	430	423	403
State —			
Current	8	44	36
Deferred	68	45	39
	76	89	75
Total	$ 506	$ 512	$ 478

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:

	2015	2014
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$ 3,917	$ 3,429
Property basis differences	456	457
Premium on reacquired debt	28	30
Employee benefit obligations	200	215
Regulatory assets associated with employee benefit obligations	375	366
Asset retirement obligations	289	59
Regulatory assets associated with asset retirement obligations	312	285
Other	175	157
Total	5,752	4,998
Deferred tax assets —		
Federal effect of state deferred taxes	242	219
Unbilled fuel revenue	39	42
Storm reserve	23	27
Employee benefit obligations	407	400
Other comprehensive losses	20	19
Asset retirement obligations	600	344
Other	180	90
Total	1,511	1,141
Accumulated deferred income taxes, net	$ 4,241	$ 3,857

On November 20, 2015, the FASB issued ASU 2015-17, which simplifies the presentation of deferred income taxes. The new guidance resulted in a reclassification from prepaid expenses of $20 million and accrued income tax of $2 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. See Note 1 under "Recently Issued Accounting Standards" for additional information.

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation in 2015 and 2014.

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At December 31, 2015 , the tax-related regulatory assets to be recovered from customers were $523 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, 2015 , the tax-related regulatory liabilities to be credited to customers were $70 million . These liabilities are primarily attributable to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $8 million in 2015, 2014 and 2013. At December 31, 2015 , all ITCs available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

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

	2015	2014	2013
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.8**	4.4	4.0
Non-deductible book depreciation	**1.2**	1.1	1.0
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.1)	(0.1)
AFUDC equity	**(1.6)**	(1.3)	(0.9)
Other	**0.1**	(0.1)	(0.1)
Effective income tax rate	**38.4%**	39.0%	38.9%

Unrecognized Tax Benefits

The Company has no material unrecognized tax benefits for 2015 or 2014. The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial and the Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 and 2014 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.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

The Company has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million as of December 31, 2015 and 2014 , which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2015 and 2014 , trust preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for this trust and the related securities.

Securities Due Within One Year

At December 31, 2015 , the Company had $200 million of senior notes and pollution control revenue bonds due within one year. At December 31, 2014 , the Company had $454 million of senior notes and pollution control revenue bonds due within one year.

Maturities through 2020 applicable to total long-term debt are as follows: $200 million in 2016; $562 million in 2017; $201 million in 2019; and $251 million in 2020. There are no material scheduled maturities in 2018.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds or installment purchases of pollution control and solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred no obligations related to the issuance of pollution control revenue bonds in 2015.

In April 2015, Alabama Power purchased and held $80 million aggregate principal amount of Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Bonds (Alabama Power Company Barry Plant Project), Series 2007-B. Alabama Power reoffered these bonds to the public in May 2015.

The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2015 and 2014 was $1.1 billion and $1.2 billion , respectively.

Senior Notes

In March 2015, the Company issued $550 million aggregate principal amount of Series 2015A 3.750% Senior Notes due March 1, 2045. The proceeds were used to redeem $250 million aggregate principal amount of Series DD 5.650% Senior Notes due March 15, 2035 and for general corporate purposes, including the Company's continuous construction program.

In April 2015, the Company issued $175 million additional aggregate principal amount of its Series 2015A 3.750% Senior Notes due March 1, 2045 (Additional Series 2015A Senior Notes) and $250 million aggregate principal amount of its Series 2015B 2.800% Senior Notes due April 1, 2025 (Series 2015B Senior Notes). A portion of the proceeds of the additional Series 2015A Senior Notes and the Series 2015B Senior Notes were used in May 2015 to redeem certain classes of the Company's preferred and preference stock plus accrued and unpaid dividends to the redemption date, and the remaining net proceeds were used for general corporate purposes, including the Company's continuous construction program. See "Redeemable Preferred Stock" herein for additional information.

At December 31, 2015 and 2014 , the Company had $5.6 billion and $5.3 billion of senior notes outstanding, respectively. As of December 31, 2015, the Company did not have any outstanding secured debt.

Subsequent to December 31, 2015, the Company issued $400 million aggregate principal amount of Series 2016A 4.30% Senior Notes due January 2, 2046. The proceeds were used to repay at maturity $200 million aggregate principal amount of Series FF 5.20% Senior Notes due January 15, 2016 and for general corporate purposes, including the Company's continuous construction program.

Redeemable Preferred and Preference Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized and outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of the Company contain a feature that allows the holders to elect a majority of the Company's board of directors if 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, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The preference stock does not contain such a provision that would allow the holders to elect a majority of the Company's board. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution.

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The Company's preferred stock is subject to redemption at a price equal to the par value plus a premium. The Company's Class A preferred stock is subject to redemption at a price equal to the stated capital. Certain series of the Company's preference stock are subject to redemption at a price equal to the stated capital plus a make-whole premium based on the present value of the liquidation amount and future dividends to the first stated capital redemption date and the other series of preference stock are subject to redemption at a price equal to the stated capital. All series of the Company's preferred stock currently are subject to redemption at the option of the Company. Information for each outstanding series is in the table below:

Preferred/Preference Stock	Par Value/Stated Capital Per Share	Shares Outstanding	Redemption Price Per Share
4.92% Preferred Stock	$100	80,000	$103.23
4.72% Preferred Stock	$100	50,000	$102.18
4.64% Preferred Stock	$100	60,000	$103.14
4.60% Preferred Stock	$100	100,000	$104.20
4.52% Preferred Stock	$100	50,000	$102.93
4.20% Preferred Stock	$100	135,115	$105.00
5.83% Class A Preferred Stock	$25	1,520,000	Stated Capital
6.450% Preference Stock	$25	6,000,000	*
6.500% Preference Stock	$25	2,000,000	*

* Prior to 10/01/2017: Stated Value Plus Make-Whole Premium; after 10/01/2017: Stated Capital

In May 2015, the Company redeemed 6.48 million shares ($162 million aggregate stated capital) of the Company's 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date and 4.0 million shares ($100 million aggregate stated capital) of the Company's 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date. Additionally, the $5 million of issuance costs were transferred from redeemable preferred stock to common stockholder's equity upon redemption. Also during May 2015, the Company redeemed 6.0 million shares ($150 million aggregate stated capital) of the Company's 5.625% Series Preference Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date. There were no changes for the years ended December 31, 2014 and 2013 in redeemable preferred stock or preference stock of the Company.

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, 2015 , committed credit arrangements with banks were as follows:

Expires					Due Within One Year	
2016	2018	2020	Total	Unused	Term Out	No Term Out
	(in millions)		(in millions)		(in millions)	
$ 40	$ 500	$ 800	$ 1,340	$ 1,340	$ —	$ 40

As reflected in the table above, in August 2015, the Company amended and restated its multi-year credit arrangements, which, among other things, extended the maturity dates from 2018 to 2020. In September 2015, the Company entered into a new $500 million three -year credit arrangement which replaced a majority of the Company's bilateral credit arrangements.

Most of the bank credit arrangements require payment of a commitment fee based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1 / 10 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

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

Most of the Company's bank credit arrangements contain covenants that limit the Company's debt to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, any long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2015 , the Company was in compliance with the debt limit covenants.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $810 million as of December 31, 2015 . In addition, at December 31, 2015, the Company had $80 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company borrows through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. The Company may also make short-term borrowings through various other arrangements with banks. At December 31, 2015 and 2014 , there was no short-term debt outstanding. At December 31, 2015 , the Company had regulatory approval to have outstanding up to $2.1 billion of short-term borrowings.

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 and nuclear fuel which are not recognized on the balance sheets. In 2015, 2014, and 2013, the Company incurred fuel expense of $1.3 billion , $1.6 billion , and $1.6 billion , 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.

In addition, the Company has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases. Total capacity expense under PPAs accounted for as operating leases was $38 million , $37 million , and $30 million for 2015, 2014, and 2013, respectively. Total estimated minimum long-term obligations at December 31, 2015 were as follows:

	Operating Lease PPAs
	(in millions)
2016	$ 39
2017	40
2018	41
2019	43
2020	44
2021 and thereafter	93
Total commitments	$ 300

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 operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has entered into rental agreements for coal railcars, vehicles, and other equipment with various terms and expiration dates. Total rent expense was $19 million in 2015 , $18 million in 2014 , and $21 million in 2013 . Of these amounts, $13 million , $14 million , and $18 million for 2015, 2014, and 2013, respectively, relate to the railcar leases and are recoverable through the Company's Rate ECR. As of December 31, 2015, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Vehicles & Other	Total
		(in millions)	
2016	$ 13	$ 6	$ 19
2017	8	5	13
2018	5	4	9
2019	5	4	9
2020	5	4	9
2021 and thereafter	13	—	13
Total	$ 49	$ 23	$ 72

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2023 with maximum obligations under these leases of $4 million in 2016 and $12 million in 2021 and thereafter. There are no obligations under these leases in 2017, 2018, 2019, and 2020. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

The Company has guaranteed the obligation of SEGCO for $25 million of pollution control revenue bonds issued in 2001, which mature in June 2019, and also $100 million of senior notes issued in November 2013, which mature in December 2018. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to Georgia Power's then proportionate ownership of SEGCO's stock if the Company is called upon to make such payment under its guarantee. See Note 4 for additional information.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation, in the form of Southern Company stock options and 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, 2015 , there were 881 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. As a result, stock-based compensation granted to employees in 2015 consisted exclusively of performance share units.

For the years ended December 31, 2014 and 2013, employees of the Company were granted stock options for 2,027,298 shares and 1,319,038 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014 and 2013 derived using the Black-Scholes stock option pricing model was $2.20 and $2.93 , respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented. As of December 31, 2015 , 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, 2015 , 2014 , and 2013 was $8 million , $21 million , and $11 million , respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $3 million , $8 million , and $4 million for the years ended December 31, 2015 , 2014 , and 2013 , respectively. As of December 31, 2015 , the aggregate intrinsic value for the options outstanding and options exercisable was $33 million and $26 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 which equates to the requisite service period for accounting purposes. 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, issued in 2015, 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, 2015 , 2014 , and 2013, employees of the Company were granted performance share units of 214,709 , 176,070 , and 141,355 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2015, 2014, and 2013, 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 $46.42 , $37.54 , and $40.50 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2015 was $47.78 .

For the years ended December 31, 2015 , 2014 , and 2013, total compensation cost for performance share units recognized in income was $13 million , $5 million , and $5 million , respectively, with the related tax benefit also recognized in income of $5 million , $2 million , and $2 million , respectively. The compensation cost and tax benefits related to the grant of Southern

Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2015 , there was $4 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 19 months .

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $13.5 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $255 million per incident but not more than an aggregate of $38 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years . The next scheduled adjustment is due no later than September 10, 2018.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. In April 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks , with a maximum per occurrence per unit limit of $490 million . After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years . The Company purchases limits based on the projected full cost of replacement power and has elected a 12-week deductible waiting period.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The current maximum annual assessments for the Company under the NEIL policies would be $55 million .

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

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

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.

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- 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, 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)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Energy-related derivatives	$ —	$ 1	$ —	$ —	$ 1
Nuclear decommissioning trusts: (*)					
Domestic equity	359	68	—	—	427
Foreign equity	47	47	—	—	94
U.S. Treasury and government agency securities	—	27	—	—	27
Corporate bonds	11	135	—	—	146
Mortgage and asset backed securities	—	18	—	—	18
Private equity	—	—	—	17	17
Other	—	5	—	—	5
Cash equivalents	68	—	—	—	68
Total	$ 485	$ 301	$ —	$ 17	$ 803
Liabilities:					
Interest rate derivatives	$ —	$ 15	$ —	$ —	$ 15
Energy-related derivatives	—	55	—	—	55
Total	$ —	$ 70	$ —	$ —	$ 70

(*) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases. See Note 1 under "Nuclear Decommissioning" for additional information.

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As of December 31, 2014 , 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, 2014:	**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:					
Energy-related derivatives	$ —	$ 1	$ —	$ —	$ 1
Nuclear decommissioning trusts: (*)					
Domestic equity	403	83	—	—	486
Foreign equity	34	63	—	—	97
U.S. Treasury and government agency securities	—	34	—	—	34
Corporate bonds	—	111	—	—	111
Mortgage and asset backed securities	—	18	—	—	18
Private equity	—	—	—	3	3
Other	—	5	—	—	5
Cash equivalents	162	—	—	—	162
Total	$ 599	$ 315	$ —	$ 3	$ 917
Liabilities:					
Interest rate derivatives	$ —	$ 8	$ —	$ —	$ 8
Energy-related derivatives	—	53	—	—	53
Total	$ —	$ 61	$ —	$ —	$ 61

(*) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflect the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. See Note 1 under "Nuclear Decommissioning" for additional information.

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

The Company early adopted ASU 2015-07 effective December 31, 2015. As required, disclosures in the paragraphs and table below are limited to only those investments in funds that are measured at net asset value as a practical expedient. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation.

As of December 31, 2015 and 2014 , the fair value measurements of private equity investments held in the nuclear decommissioning trusts that are calculated at net asset value per share (or its equivalent) as a practical expedient, as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
As of December 31, 2015	**$ 17**	**$ 28**	**Not Applicable**	**Not Applicable**
As of December 31, 2014	$ 3	$ 7	Not Applicable	Not Applicable

Private equity funds include a fund-of-funds that invests in high quality private equity funds across several market sectors, a fund that invests in real estate assets, and a fund that acquires companies to create resale value. Private equity funds do not have redemption rights. Distributions from these funds will be received as the underlying investments in the funds are liquidated. Liquidations of these investments are expected to occur at various times over the next ten years .

As of December 31, 2015 and 2014 , 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, including securities due within one year:		
2015	**$ 6,849**	**$ 7,192**
2014	$ 6,586	$ 7,321

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 available to the Company.

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 10 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 commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Alabama PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

Energy-related derivative contracts are accounted for under one of two methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the energy cost recovery clause.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2015 , the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
(in millions)		
50	2018	—

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 earnings.

At December 31, 2015 , the following interest rate derivative was outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2015
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$ 200	3-month LIBOR	2.93%	October 2025	$ (15)

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2016 are $4 million . The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

Derivative Financial Statement Presentation and Amounts

At December 31, 2015 and 2014 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 1**	$ 1	Liabilities from risk management activities	**$ 40**	$ 32
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**15**	21
Total derivatives designated as hedging instruments for regulatory purposes		**$ 1**	$ 1		**$ 55**	$ 53
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**$ —**	**$ —**	Liabilities from risk management activities	**$ 15**	$ 8
Total		**$ 1**	$ 1		**$ 70**	$ 61

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2015 and 2014 .

The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2015 and 2014 are presented in the following tables. Interest rate derivatives presented in the tables above do not have amounts available for offset and are therefore excluded from the offsetting disclosure table below.

Fair Value					
Assets	**2015**	2014	**Liabilities**	**2015**	2014
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 1**	$ 1	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 55**	$ 53
Gross amounts not offset in the Balance Sheet [(b)]	**(1)**	—	Gross amounts not offset in the Balance Sheet [(b)]	**(1)**	—
Net energy-related derivative assets	**$ —**	$ 1	**Net energy-related derivative liabilities**	**$ 54**	$ 53

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

At December 31, 2015 and 2014 , the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (40)**	$ (32)	Other current liabilities	**$ 1**	$ 1
	Other regulatory assets, deferred	**(15)**	(21)	Other regulatory liabilities, deferred	**—**	—
Total energy-related derivative gains (losses)		**$ (55)**	$ (53)		**$ 1**	$ 1

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2015**	2014	2013	**Statements of Income Location**	**2015**	2014	2013
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ (7)**	$ (8)	$ —	Interest expense, net of amounts capitalized	**$ (3)**	$ (3)	$ (3)

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

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2015 , the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2015 , the fair value of derivative liabilities with contingent features was $16 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $52 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2015 and 2014 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2015	**$ 1,401**	**$ 346**	**$ 169**
June 2015	**1,455**	**398**	**200**
September 2015	**1,695**	**555**	**295**
December 2015	**1,217**	**264**	**121**
March 2014	$ 1,508	$ 381	$ 187
June 2014	1,437	357	173
September 2014	1,669	520	282
December 2014	1,328	267	119

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

SELECTED FINANCIAL AND OPERATING DATA 2011 - 2015
Alabama Power Company 2015 Annual Report

	2015	2014	2013	2012	2011
Operating Revenues (in millions)	**$ 5,768**	$ 5,942	$ 5,618	$ 5,520	$ 5,702
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 785**	$ 761	$ 712	$ 704	$ 708
Cash Dividends on Common Stock (in millions)	**$ 571**	$ 550	$ 644	$ 684	$ 774
Return on Average Common Equity (percent)	**13.37**	13.52	13.07	13.10	13.19
Total Assets (in millions) [(a)(b)]	**$ 21,721**	$ 20,493	$ 19,185	$ 18,647	$ 18,397
Gross Property Additions (in millions)	**$ 1,492**	$ 1,543	$ 1,204	$ 940	$ 1,016
Capitalization (in millions):					
Common stock equity	**$ 5,992**	$ 5,752	$ 5,502	$ 5,398	$ 5,342
Preference stock	**196**	343	343	343	343
Redeemable preferred stock	**85**	342	342	342	342
Long-term debt [(a)]	**6,654**	6,137	6,195	5,890	5,586
Total (excluding amounts due within one year)	**$ 12,927**	$ 12,574	$ 12,382	$ 11,973	$ 11,613
Capitalization Ratios (percent):					
Common stock equity	**46.4**	45.8	44.4	45.1	46.0
Preference stock	**1.5**	2.7	2.8	2.9	3.0
Redeemable preferred stock	**0.7**	2.7	2.7	2.9	2.9
Long-term debt [(a)]	**51.4**	48.8	50.1	49.1	48.1
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**1,253,875**	1,247,061	1,241,998	1,237,730	1,231,574
Commercial	**197,920**	197,082	196,209	196,177	196,270
Industrial	**6,056**	6,032	5,851	5,839	5,844
Other	**757**	753	751	748	746
Total	**1,458,608**	1,450,928	1,444,809	1,440,494	1,434,434
Employees (year-end)	**6,986**	6,935	6,896	6,778	6,632

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $40 million, $38 million, $39 million, and $47 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-03. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(b) A reclassification of deferred tax assets from Total Assets of $20 million, $27 million, $27 million, and $33 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-17. See Note 1 under "Recently Issued Accounting Standards" for additional information.

SELECTED FINANCIAL AND OPERATING DATA 2011 - 2015 (continued)
Alabama Power Company 2015 Annual Report

	2015	2014	2013	2012	2011
Operating Revenues (in millions):					
Residential	$ 2,207	$ 2,209	$ 2,079	$ 2,068	$ 2,144
Commercial	1,564	1,533	1,477	1,491	1,495
Industrial	1,436	1,480	1,369	1,346	1,306
Other	27	27	27	28	27
Total retail	5,234	5,249	4,952	4,933	4,972
Wholesale — non-affiliates	241	281	248	277	287
Wholesale — affiliates	84	189	212	111	244
Total revenues from sales of electricity	5,559	5,719	5,412	5,321	5,503
Other revenues	209	223	206	199	199
Total	$ 5,768	$ 5,942	$ 5,618	$ 5,520	$ 5,702
Kilowatt-Hour Sales (in millions):					
Residential	18,082	18,726	17,920	17,612	18,650
Commercial	14,102	14,118	13,892	13,963	14,173
Industrial	23,380	23,799	22,904	22,158	21,666
Other	201	211	211	214	214
Total retail	55,765	56,854	54,927	53,947	54,703
Wholesale — non-affiliates	3,567	3,588	3,711	4,196	4,330
Wholesale — affiliates	4,515	6,713	7,672	4,279	7,211
Total	63,847	67,155	66,310	62,422	66,244
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.21	11.80	11.60	11.74	11.50
Commercial	11.09	10.86	10.63	10.68	10.55
Industrial	6.14	6.22	5.98	6.07	6.03
Total retail	9.39	9.23	9.02	9.14	9.09
Wholesale	4.02	4.56	4.04	4.58	4.60
Total sales	8.71	8.52	8.16	8.52	8.31
Residential Average Annual Kilowatt-Hour Use Per Customer	14,454	15,051	14,451	14,252	15,138
Residential Average Annual Revenue Per Customer	$ 1,764	$ 1,775	$ 1,676	$ 1,674	$ 1,740
Plant Nameplate Capacity Ratings (year-end) (megawatts)	11,797	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	12,162	11,761	9,347	10,285	11,553
Summer	11,292	11,054	10,692	11,096	11,500
Annual Load Factor (percent)	58.4	61.4	64.9	61.3	60.6
Plant Availability (percent) * :					
Fossil-steam	81.5	82.5	87.3	88.6	88.7
Nuclear	92.1	93.3	90.7	94.5	94.7
Source of Energy Supply (percent):					
Coal	49.1	49.0	50.0	48.2	52.5
Nuclear	21.3	20.7	20.3	22.6	20.8
Hydro	5.6	5.5	8.1	4.1	4.6
Gas	14.6	15.4	15.7	16.8	15.3
Purchased power —					
From non-affiliates	4.4	3.6	2.9	2.0	0.9
From affiliates	5.0	5.8	3.0	6.3	5.9

Total	**100.0**	100.0	100.0	100.0	100.0

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

GEORGIA POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2015 Annual Report

The management of Georgia Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (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, 2015 .

/s/ W. Paul Bowers
W. Paul Bowers
Chairman, President, and Chief Executive Officer

/s/ W. Ron Hinson
W. Ron Hinson
Executive Vice President, Chief Financial Officer, Treasurer, and Corporate Secretary

February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2015 and 2014 , and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2015 . 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 II-239 to II-287) present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2015 and 2014 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015 , in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 26, 2016

DEFINITIONS

Term	Meaning
2013 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2014 through 2016
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CWIP	Construction work in progress
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
GAAP	U.S. generally accepted accounting principles
Gulf Power	Gulf Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NCCR	Nuclear Construction Cost Recovery
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power Company, Gulf Power, and Mississippi Power

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Georgia Power Company 2015 Annual Report

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, and fuel. In addition, construction continues on Plant Vogtle Units 3 and 4. The Company will own a 45.7% interest in these two nuclear generating units to increase its generation diversity and meet future supply needs. On December 31, 2015, the Company and the other parties to the commercial litigation related to the construction of Plant Vogtle Units 3 and 4 entered into a settlement agreement resulting in the dismissal of the litigation. The Company has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information on Plant Vogtle Units 3 and 4.

In accordance with the 2013 ARP approved by the Georgia PSC, the Company increased base rates approximately $110 million, $136 million, and $140 million effective January 1, 2014, 2015, and 2016, respectively. The Company is required to file its next base rate case by July 1, 2016. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate Plans" herein for additional information.

Key Performance Indicators

The Company continues to focus on several key performance indicators, including, but not limited to, customer satisfaction, plant availability, system reliability, the execution of major construction projects, and net income after dividends on preferred and preference 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 of these surveys in measuring performance, which the Company achieved during 2015.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's 2015 Peak Season EFOR of 1.21% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages, with performance targets set based on historical performance. The Company's 2015 performance was below the target for these transmission and distribution reliability measures primarily due to the level of storm activity in the service territory during the year.

The Company uses net income after dividends on preferred and preference stock as the primary measure of the Company's financial performance. See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Earnings

The Company's 2015 net income after dividends on preferred and preference stock was $1.3 billion, representing a $35 million, or 2.9%, increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1, 2015, as authorized by the Georgia PSC, and lower non-fuel operations and maintenance expenses, partially offset by the correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing. See Note 1 to the financial statements under "General" for additional information.

The Company's 2014 net income after dividends on preferred and preference stock was $1.2 billion, representing a $51 million, or 4.3%, increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1, 2014, as authorized under the 2013 ARP, and colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013, partially offset by higher non-fuel operations and maintenance expenses.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2015 Annual Report

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2015	**2015**	2014
		(in millions)	
Operating revenues	**$ 8,326**	**$ (662)**	$ 714
Fuel	**2,033**	**(514)**	240
Purchased power	**864**	**(124)**	104
Other operations and maintenance	**1,844**	**(58)**	248
Depreciation and amortization	**846**	**—**	39
Taxes other than income taxes	**391**	**(18)**	27
Total operating expenses	**5,978**	**(714)**	658
Operating income	**2,348**	**52**	56
Interest expense, net of amounts capitalized	**363**	**15**	(13)
Other income (expense), net	**61**	**38**	(12)
Income taxes	**769**	**40**	6
Net income	**1,277**	**35**	51
Dividends on preferred and preference stock	**17**	**—**	—
Net income after dividends on preferred and preference stock	**$ 1,260**	**$ 35**	$ 51

Operating Revenues

Operating revenues for 2015 were $8.3 billion, reflecting a $662 million decrease from 2014. Details of operating revenues were as follows:

	Amount	
	2015	2014
	(in millions)	
Retail — prior year	**$ 8,240**	$ 7,620
Estimated change resulting from —		
Rates and pricing	**88**	183
Sales growth	**63**	21
Weather	**(19)**	139
Fuel cost recovery	**(645)**	277
Retail — current year	**7,727**	8,240
Wholesale revenues —		
Non-affiliates	**215**	335
Affiliates	**20**	42
Total wholesale revenues	**235**	377
Other operating revenues	**364**	371
Total operating revenues	**$ 8,326**	$ 8,988
Percent change	**(7.4)%**	8.6%

Retail base revenues of $5.3 billion in 2015 increased $133 million, or 2.6%, compared to 2014. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to base tariff increases effective January 1, 2015, as approved by the Georgia PSC in accordance with the 2013 ARP, and increases in collections for financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, partially offset by the correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing. In 2015, residential base revenues increased $104 million, or 4.5%, commercial base revenues increased $70 million, or 3.4%, and industrial base revenues decreased $41 million, or 5.6%, compared to 2014.

Retail base revenues of $5.2 billion in 2014 increased $343 million, or 7.1%, compared to 2013. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to base tariff increases effective January 1, 2014, as approved by the Georgia PSC in accordance with the 2013 ARP, and increases in collections for financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff as well as higher contributions from variable demand-driven pricing from commercial and industrial customers. In 2014, residential base revenues increased $163 million, or 7.6%, commercial base revenues increased $108 million, or 5.5%, and industrial base revenues increased $74 million, or 11.1%, compared to 2013.

See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses and do not affect net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from power sales to non-affiliated utilities were as follows:

	2015	2014	2013
		(in millions)	
Capacity and other	**$ 108**	$ 164	$ 174
Energy	**107**	171	107
Total non-affiliated	**$ 215**	$ 335	$ 281

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amounts billable under the contract terms and provide for recovery of fixed costs and a return on investment. Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy.

Wholesale revenues from non-affiliated sales decreased $120 million, or 35.8%, in 2015 as compared to 2014 and increased $54 million, or 19.2%, in 2014 as compared to 2013. The decrease in 2015 was related to decreases of $64 million in energy revenues and $56 million in capacity revenues. The decrease in energy revenues was primarily due to lower natural gas prices. The decrease in capacity revenues reflects the expiration of wholesale contracts in December 2014 and the retirement of 14 coal-fired generating units as a result of the Company's environmental compliance strategy. The increase in 2014 was primarily due to increased demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and the lower cost of Company-owned generation compared to the market cost of available energy. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" and – "Retail Regulatory Matters – Integrated Resource Plan" herein for additional information regarding the Company's environmental compliance strategy.

Wholesale revenues from sales to affiliated companies 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. In 2015, wholesale revenues from sales to affiliates decreased $22 million as compared to 2014 due to lower natural gas prices and a 50.6% decrease in KWH sales due to the higher cost of Company-owned generation compared to the market cost of available energy. In 2014, wholesale revenues from sales to affiliates increased $22 million as compared to 2013 due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and the lower cost of Company-owned generation.

Other operating revenues decreased $7 million, or 1.9%, in 2015 from the prior year primarily due to a $16 million decrease in transmission service revenues primarily as a result of a contract that expired in December 2014, partially offset by an $11 million increase in outdoor lighting revenues . Other operating revenues increased $18 million, or 5.1%, in 2014 from the prior year primarily due to $7 million in transmission service revenues, $5 million of solar application fee revenues, and $5 million in outdoor lighting revenues.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2015 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2015	**2015**	2014	**2015**	2014
	(in billions)				
Residential	**26.7**	**(1.8)%**	6.5%	**1.0%**	0.5%
Commercial	**32.7**	**0.9**	1.4	**1.5**	(0.2)
Industrial	**23.8**	**1.1**	2.0	**1.0**	1.5
Other	**0.6**	**(0.2)**	0.5	**(0.1)**	0.3
Total retail	**83.8**	**0.1**	3.2	**1.2%**	0.5%
Wholesale					
Non-affiliates	**3.5**	**(19.0)**	42.6		
Affiliates	**0.6**	**(50.6)**	125.4		
Total wholesale	**4.1**	**(25.5)**	54.2		
Total energy sales	**87.9**	**(1.5)%**	5.3%		

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.

In 2015, KWH sales for the residential class decreased compared to 2014 primarily due to milder weather in the first and fourth quarters 2015 as compared to the corresponding periods in 2014 and decreased customer usage, partially offset by an increase in customer growth. Weather-adjusted residential KWH sales increased by 1.0% primarily due to an increase of approximately 25,000 residential customers during 2015. Household income, one of the primary drivers of residential customer usage, had modest growth in 2015. Weather-adjusted commercial KWH sales increased by 1.5% primarily due to an increase of approximately 3,000 customers and an increase in customer usage. Weather-adjusted industrial KWH sales increased by 1.0% primarily due to increased demand in the pipeline, rubber, and paper sectors, partially offset by decreased demand in the chemicals and primary metals sectors.

In 2014, KWH sales for residential and commercial customer classes increased compared to 2013 primarily due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and customer growth, partially offset by decreased customer usage. Industrial sales increased in 2014 compared to 2013. Increased demand in the paper, textiles, and stone, clay, and glass sectors was the main contributor to the increase in industrial sales in 2014 compared to 2013. Weather-adjusted commercial KWH sales decreased by 0.2% primarily due to decreased customer usage, largely offset by customer growth. Weather-adjusted residential KWH sales increased by 0.5% primarily due to customer growth, largely offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses

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

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

	2015	2014	2013
Total generation *(billions of KWHs)*	**65.9**	69.9	66.8
Total purchased power *(billions of KWHs)*	**25.6**	23.1	21.4
Sources of generation *(percent)* —			
Coal	**34**	41	35
Nuclear	**25**	22	23
Gas	**39**	35	39
Hydro	**2**	2	3
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**4.55**	4.52	4.92
Nuclear	**0.78**	0.90	0.91
Gas	**2.47**	3.67	3.33
Average cost of fuel, generated *(cents per net KWH)*	**2.77**	3.40	3.32
Average cost of purchased power *(cents per net KWH)**	**4.33**	5.20	4.83

* Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $2.9 billion in 2015, a decrease of $638 million, or 18.0%, compared to 2014. The decrease was primarily due to a $544 million decrease in the average cost of fuel and purchased power largely as a result of lower natural gas prices and a $228 million decrease in the volume of KWHs generated by coal, partially offset by a $134 million increase in the volume of KWHs purchased due to lower natural gas prices.

Fuel and purchased power expenses were $3.5 billion in 2014, an increase of $344 million, or 10.8%, compared to 2013. The increase was primarily due to a $292 million increase in the volume of KWHs generated and purchased due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 driving higher customer demand and an increase of $84 million in the average cost of purchased power primarily due to higher natural gas prices, partially offset by a $32 million decrease in the average cost of fuel primarily due to lower coal prices.

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

Fuel

Fuel expense was $2.0 billion in 2015, a decrease of $514 million, or 20.2%, compared to 2014. The decrease was primarily due to a decrease of 32.7% in the average cost of natural gas per KWH generated and a decrease of 22.2% in the volume of KWHs generated by coal, partially offset by a 6.2% increase in the volume of KWHs generated by natural gas. Fuel expense was $2.5 billion in 2014, an increase of $240 million, or 10.4%, compared to 2013. The increase was primarily due to an increase of 5.7% in the volume of KWHs generated as a result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 driving higher customer demand and a 2.4% increase in the average cost of fuel per KWH generated primarily due to higher natural gas prices, partially offset by lower coal prices.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $289 million in 2015, an increase of $2 million, or 0.7%, compared to 2014. The increase was primarily due to a 28.1% increase in the volume of KWHs purchased to meet customer demand, partially offset by a 19.8% decrease in the average cost per KWH purchased due to lower natural gas prices. Purchased power expense from non-affiliates was $287 million in 2014, an increase of $63 million, or 28.1%, compared to 2013. The increase was primarily due to a 6.1% increase in the average cost per KWH purchased primarily resulting from higher natural gas prices and a 22.0% increase in the volume of KWHs purchased to meet higher customer demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013.

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

Purchased Power - Affiliates

Purchased power expense from affiliates was $575 million in 2015, a decrease of $126 million, or 18.0%, compared to 2014. The decrease was primarily due to a decrease of 17.4% in the average cost per KWH purchased reflecting lower natural gas prices, partially offset by an 8.1% increase in the volume of KWHs purchased to meet customer demand. Purchased power expense from affiliates was $701 million in 2014, an increase of $41 million, or 6.2%, compared to 2013. The increase was primarily due to an increase of 5.8% in the average cost per KWH purchased reflecting higher natural gas prices and a 5.6% increase in the volume of KWHs purchased to meet higher customer demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013.

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

Other Operations and Maintenance Expenses

In 2015, other operations and maintenance expenses decreased $58 million, or 3.0%, compared to 2014. The decrease was primarily due to decreases of $51 million in transmission operating expenses, primarily due to gains from sales of assets and billing adjustments with integrated transmission system owners, $28 million in transmission and distribution overhead line maintenance, and $11 million in workers compensation and legal expense related to a lower volume of claims, partially offset by an increase of $33 million in employee benefits including pension costs. See Note 2 to the financial statements for additional information on pension costs.

In 2014, other operations and maintenance expenses increased $248 million, or 15.0%, compared to 2013. The increase was primarily due to increases of $74 million in transmission and distribution overhead line maintenance expenses, $58 million in generation expense to meet higher demand, $52 million in scheduled outage-related costs, $35 million in customer assistance expenses related to customer incentive and demand-side management costs, and $11 million in the storm damage accrual as authorized in the 2013 ARP.

Depreciation and Amortization

Depreciation and amortization remained flat in 2015 compared to 2014 primarily due to a $16 million decrease related to unit retirements and a $9 million decrease related to other cost of removal obligations, partially offset by a $23 million increase related to additional plant in service.

Depreciation and amortization increased $39 million, or 4.8%, in 2014 compared to 2013. The increase was primarily due to decreases of $36 million and $17 million in amortization of regulatory liabilities related to state income tax credits that was completed in December 2013 and other cost of removal obligations as authorized in the 2013 ARP, respectively, partially offset by a decrease of $14 million in depreciation and amortization also as authorized in the 2013 ARP.

See Note 1 to the financial statements under "Depreciation and Amortization" for additional information.

Taxes Other Than Income Taxes

In 2015, taxes other than income taxes decreased $18 million, or 4.4%, compared to 2014. The decrease was primarily due to decreases of $15 million in municipal franchise fees related to lower retail revenues and $5 million in payroll taxes.

In 2014, taxes other than income taxes increased $27 million, or 7.1%, compared to 2013. The increase was primarily due to increases of $24 million in municipal franchise fees related to higher retail revenues and $9 million in payroll taxes, partially offset by a $6 million decrease in property taxes.

Interest Expense, Net of Amounts Capitalized

In 2015, interest expense, net of amounts capitalized increased $15 million, or 4.3%, from the prior year. The increase was primarily due to a $23 million increase in interest due to additional long-term debt borrowings from the FFB, partially offset by an $11 million decrease in interest on senior notes due to redemptions and maturities.

In 2014, interest expense, net of amounts capitalized decreased $13 million, or 3.6%, from the prior year. The decrease was primarily due to a $40 million decrease in interest on long-term debt resulting from redemptions and refinancing of long-term debt at lower interest rates and a $4 million increase in interest capitalized as a result of increased construction activity, partially offset by a $32 million increase in interest on outstanding long-term debt borrowings from the FFB.

Other Income (Expense), Net

In 2015, other income (expense), net increased $38 million from the prior year primarily due to increases of $9 million in wholesale operating fee revenue and $9 million in customer contributions in aid of construction, as well as a $9 million decrease in donations.

In 2014, other income (expense), net decreased $12 million from the prior year primarily due to a $9 million increase in donations and an $8 million decrease in wholesale operating fee revenue, partially offset by an increase in AFUDC equity due to an increase in construction related to ongoing environmental and transmission projects.

Income Taxes

Income taxes increased $40 million, or 5.5%, in 2015 compared to the prior year primarily due to higher pre-tax earnings and the recognition in 2014 of tax benefits related to emissions allowances and state apportionment.

Income taxes increased $6 million, or 0.8%, in 2014 compared to the prior year primarily due to higher pre-tax earnings and an increase in non-deductible book depreciation, partially offset by the recognition of tax benefits related to emission allowances and state apportionment, an increase in non-taxable AFUDC equity, and state income tax credits.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the completion and subsequent operation of ongoing construction projects, primarily Plant Vogtle Units 3 and 4. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, 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 partially 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.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. The Company's Environmental Compliance Cost Recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. 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 2015 , the Company had invested approximately $5.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $0.3 billion, $0.4 billion, and $0.3 billion for 2015 , 2014 , and 2013 , respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $0.7 billion from 2016 through 2018 , with annual totals of approximately $0.3 billion, $0.2 billion, and $0.2 billion for 2016 , 2017 , and 2018 , respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with closure in place or by other methods, and ground water monitoring of ash ponds in accordance with the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation (ARO) liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, 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 – Integrated Resource Plan" herein for additional information on planned unit retirements and fuel conversions.

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. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. The compliance deadline set by the final MATS rule was April 16, 2015, with provisions for extensions to April 16, 2016. The implementation strategy for the MATS rule includes emission controls, retirements, and fuel conversions to achieve compliance by the deadlines applicable to each Company unit. On June 29, 2015, the U.S. Supreme Court issued a decision finding that in developing the MATS rule the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units. On December 15, 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule to the EPA without vacatur to respond to the U.S. Supreme Court's decision. The EPA's supplemental finding in response to the U.S. Supreme Court's decision, which the EPA proposes to finalize in April 2016, is not expected to have any impact on the MATS rule compliance requirements and deadlines.

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. The only area within the Company's service territory designated as an ozone nonattainment area for the 2008 standard is a 15-county area within metropolitan Atlanta. On October 26, 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 will recommend area designations by October 2016, and the EPA is expected to finalize them by October 2017.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS and the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard in December 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred designation decisions for certain areas in Georgia.

Final revisions to the NAAQS for sulfur dioxide (SO_2) , which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has finalized a data requirements rule to support additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I having begun in 2015 and Phase II beginning in 2017. On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Georgia, Alabama, and Florida, but rejected all other pending challenges to the rule. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. On December 3, 2015, the EPA published a proposed revision to CSAPR that would revise existing ozone-season emissions budgets for nitrogen oxide in Alabama and would remove Florida from the CSAPR program. The EPA proposes to finalize this rulemaking by summer 2016.

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.

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

On June 12, 2015, the EPA published a final rule requiring certain states (including Georgia, Alabama, and Florida) to revise or remove the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM) by no later than November 22, 2016.

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. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, CSAPR, regional haze regulations, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. 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.

In addition to the federal air quality laws described above, the Company has also been subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule and a companion rule required reductions in emissions of mercury, SO_2 , and nitrogen oxide state-wide through the installation of specified control technologies and a 95% reduction in SO_2 emissions at certain coal-fired generating units by specific dates between 2008 and 2015. In 2015, the Company completed implementation of the measures necessary to comply with the Georgia Multi-Pollutant Rule at all 16 of its coal-fired generating units required to be controlled under the rule.

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 October 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

On November 3, 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 National Pollutant Discharge Elimination System 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. The ultimate impact of these requirements will depend on pending and any future legal challenges, compliance dates, and implementation of the final rule and cannot be determined at this time.

On June 29, 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 August 28, 2015, but on October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The ultimate impact of the final rule will depend on the outcome of this and other pending legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs.

Coal Combustion Residuals

The Company currently manages CCR at onsite units consisting of landfills and surface impoundments (CCR Units) at 11 electric generating plants, including some that have recently retired. 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 State of Georgia has its own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On April 17, 2015, the EPA published the CCR Rule in the Federal Register, which became effective on October 19, 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. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

Based on initial cost estimates for closure in place or by other methods, and groundwater monitoring of ash ponds pursuant to the CCR Rule, the Company recorded incremental 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, 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. The Company is currently completing an analysis of the plan of closure for all ash ponds, including the timing of closure and related cost recovery through regulated rates subject to Georgia PSC approval. Based on the results of that analysis, the Company may accelerate the timing of some ash pond closures which could increase its ARO liabilities from the amounts presently recorded. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. 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, 2015.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up 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. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Notes 1 and 3 to the financial statements under "Environmental Remediation Recovery" and "Environmental Matters – Environmental Remediation," respectively, for additional information.

Global Climate Issues

On October 23, 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 its review with the courts. The stay will remain in effect through the resolution of the litigation, whether resolved in the U.S. Court of Appeals for the District of Columbia Circuit or 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. 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 Company's ongoing review of the final rules; the outcome of legal challenges, including legal challenges filed by the traditional operating companies; individual state implementation of the EPA's final guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

The United Nations 21st international climate change conference took place in late 2015. The result was the adoption of 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 increasing those commitments every five years. The ultimate impact of this agreement depends on its ratification and implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2014 greenhouse gas emissions were approximately 38 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2015 greenhouse gas emissions on the same basis is approximately 31 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

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 operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional 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 operating companies and in some adjacent areas. The FERC directed the traditional operating companies (including the

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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 operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

The Company's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. The Company currently recovers its costs from the regulated retail business through the 2013 ARP, which includes traditional base tariff rates, Demand-Side Management (DSM) tariffs, ECCR tariffs, and Municipal Franchise Fee (MFF) tariffs. In addition, financing costs related to the construction of Plant Vogtle Units 3 and 4 are being collected through the NCCR tariff and fuel costs are collected through separate fuel cost recovery tariffs. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Rate Plans

In 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors.

On December 16, 2015, in accordance with the 2013 ARP, the Georgia PSC approved an increase to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million ; (2) ECCR tariff by approximately $75 million ; (3) DSM tariffs by approximately $3 million ; and (4) MFF tariff by approximately $13 million , for a total increase in base revenues of approximately $140 million .

Under the 2013 ARP, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00% . Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, the Company's retail ROE exceeded 12.00% , and the Company will refund to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, the Company's retail ROE was within the allowed retail ROE range.

The Company is required to file a general base rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Renewables

In May 2014, the Georgia PSC approved the Company's application for the certification of two PPAs executed in 2013 for the purchase of energy from two wind farms in Oklahoma with capacity totaling 250 MWs that will begin in 2016 and end in 2035.

As part of the Georgia Power Advanced Solar Initiative (ASI), the Company executed ten PPAs that were approved by the Georgia PSC in 2014 and provide for the purchase of energy from 515 MWs of solar capacity. Two PPAs began in December 2015 and eight are expected to begin in December 2016, all of which have terms ranging from 20 to 30 years. As a result of certain acquisitions by Southern Power, the Company expects that 249 MWs of the 515 MWs of contracted capacity will be purchased from solar facilities owned or under development by Southern Power.

In October 2014, the Georgia PSC approved the Company's request to build, own, and operate three 30-MW solar generation facilities at three U.S. Army bases by the end of 2016. One of the three solar generation facilities began commercial operation on December 31, 2015. In addition, in December 2014, the Georgia PSC approved the Company's request to build, own, and operate a 30-MW solar generation facility at Kings Bay Naval facility. On July 21, 2015, the Georgia PSC approved the Company's request to build and operate an up to 46-MW solar generation facility at a U.S. Marine Corps base in Albany, Georgia. The Company subsequently determined that a 31-MW facility will be constructed on the site. On December 22, 2015, the Georgia PSC approved the Company's request to build and operate the remaining 15 MWs at a separate facility on the Fort Stewart Army base in Hinesville, Georgia. These facilities are expected to be operational by the end of 2016.

On April 7, 2015, the Georgia PSC approved the consolidation of four PPAs each with the same counterparty into two new PPAs with new biomass facilities. Under the terms of the order, the total 116 MWs from the existing four PPAs provided the capacity for two new PPAs of 58 MWs each. The new PPAs were executed on June 15, 2015 and November 23, 2015 and will begin in June 2017. See "Integrated Resource Plan" herein for additional information on renewables.

Integrated Resource Plan

See "Environmental Matters" and "Rate Plans" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent limitations guidelines for steam electric power plants, and additional regulations of CCR and CO_2; the State of Georgia's Multi-Pollutant Rule; and the Company's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations.

To comply with the April 16, 2015 effective date of the MATS rule, Plant Branch Units 1, 3, and 4 (1,266 MWs) , Plant Yates Units 1 through 5 (579 MWs) , and Plant McManus Units 1 and 2 (122 MWs) were retired and operations were discontinued at Plant Mitchell Unit 3 (155 MWs) by April 15, 2015, and Plant Kraft Units 1 through 4 (316 MWs) were retired on October 13, 2015. The switch to natural gas as the primary fuel was completed at Plant Yates Units 6 and 7 by June 2015 and at Plant Gaston Units 1 through 4 by December 2015.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years ending December 2022 and the amortization of the remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024.

On January 29, 2016, the Company filed its triennial IRP (2016 IRP). The filing included a request to decertify Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs) upon approval of the 2016 IRP. The 2016 IRP also reflects that the Company exercised its contractual option to sell its 33% ownership interest in the Intercession City unit (143 MWs total capacity) to Duke Energy Florida, Inc. See Note 4 to the financial statements for additional information.

In the 2016 IRP, the Company requested reclassification of the remaining net book value of Plant Mitchell Unit 3, as of its retirement date, to a regulatory asset to be amortized over a period equal to the unit's remaining useful life. The Company also requested that the Georgia PSC approve the deferral of the cost associated with materials and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a period deemed appropriate by the Georgia PSC.

The decertification and retirement of these units are not expected to have a material impact on the Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's orders in the 2016 IRP and next general base rate case.

Additionally, the 2016 IRP included a Renewable Energy Development Initiative requesting to procure up to 525 MWs of renewable resources utilizing market-based prices established through a competitive bidding process to expand the Company's existing renewable initiatives, including ASI.

A decision from the Georgia PSC on the 2016 IRP is expected in the third quarter 2016. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million . On December 15, 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016. The Company's fuel cost recovery mechanism includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC allowing the use of an array of derivative instruments within a 48-month time horizon effective January 1, 2016.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (Westinghouse and Stone & Webster, Inc., collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not occurred), with maximum additional capital costs under this provision attributable to the Company (based on the

Company's ownership interest) of approximately $114 million . Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7% .

On December 31, 2015, Westinghouse acquired Stone & Webster, Inc. from CB&I (Acquisition). In connection with the Acquisition, Stone & Webster, Inc. changed its name to WECTEC Global Project Services Inc. (WECTEC). Certain obligations of Westinghouse and Stone & Webster, Inc. have been guaranteed by Toshiba Corporation, Westinghouse's parent company, and CB&I's The Shaw Group Inc., respectively. Subject to the consent of the DOE, in connection with the Acquisition and pursuant to the settlement agreement described below, the guarantee of The Shaw Group Inc. will be terminated. The guarantee of Toshiba Corporation remains in place. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement. Additionally, on January 13, 2016, as a result of recent credit rating downgrades of Toshiba Corporation, Westinghouse provided the Vogtle Owners with letters of credit in an aggregate amount of $900 million in accordance with, and subject to adjustment under, the terms of the Vogtle 3 and 4 Agreement.

The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events.

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges may arise as construction proceeds.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved an initial NCCR tariff of approximately $223 million effective January 1, 2011, as well as increases to the NCCR tariff of approximately $35 million , $50 million , $60 million , $27 million , and $19 million effective January 1, 2012, 2013, 2014, 2015, and 2016, respectively.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected construction capital costs to be borne by the Company increase by 5% above the certified cost or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. In February 2013, the Company requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 (from April 2016) and the fourth quarter 2018 (from April 2017) for Plant Vogtle Units 3 and 4, respectively. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between the Company and the Georgia PSC Staff (Staff) to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and the Company.

On April 15, 2015, the Georgia PSC issued a procedural order in connection with the twelfth VCM report, which included a requested amendment (Requested Amendment) to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 (second quarter of 2019 and second quarter of 2020, respectively) as well as additional estimated Vogtle Owner's costs, of approximately $10 million per month, including property taxes, oversight costs, compliance costs, and other operational readiness costs to include the estimated Vogtle Owner's costs associated with the proposed 18-month Contractor delay and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion . Pursuant to the Georgia PSC's procedural order, the Georgia PSC deemed the Requested Amendment unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation. The Georgia PSC recognized that the certified cost and the 2013 Stipulation do not constitute a cost recovery cap. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by the Company in excess of the certified amount will be included in rate base, provided the Company shows the costs to be reasonable and prudent. Financing costs up to the certified amount will be collected through the NCCR tariff until the units are placed in service and contemplated in a general base rate case, while financing costs on any construction-related costs in excess of the $4.4 billion certified amount are expected to be recovered through AFUDC.

In 2012, the Vogtle Owners and the Contractor commenced litigation regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The Contractor also asserted that it was entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. In May 2014, the Contractor filed an amended claim alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. In June 2015, the Contractor updated its estimated damages to an aggregate (based on the Company's ownership interest) of approximately $714 million (in 2015 dollars). The case was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation).

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including the Vogtle Construction Litigation. Effective December 31, 2015, the Company, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to match the current estimated in-service dates of June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will now commence from the current estimated nuclear fuel loading date for each unit, which is December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4, rather than the original guaranteed substantial completion dates under the Vogtle 3 and 4 Agreement; and (v) provide that the Company, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million , of which approximately $120 million has been paid previously under the dispute resolution procedures of the Vogtle 3 and 4 Agreement. Further, subsequent to December 31, 2015, the Company paid approximately $121 million under the terms of the Contractor Settlement Agreement. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs were reflected in the Company's previously disclosed in-service cost estimate. Further, as part of the settlement and in connection with the Acquisition: (i) Westinghouse has engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor; and (ii) the Vogtle Owners, CB&I, and The Shaw Group Inc. have entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On January 21, 2016, the Company submitted the Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement to the Georgia PSC for its review. On February 2, 2016, the Georgia PSC ordered the Company to file supplemental information by April 5, 2016 in support of the Contractor Settlement Agreement and the Company's position that all construction costs to date have been prudently incurred and that the current estimated in-service capital cost and schedule are reasonable. Following the Company's filing under the order, the Staff will conduct a review of all costs incurred related to Plant Vogtle Units 3 and 4, the schedule for completion of Plant Vogtle Units 3 and 4, and the Contractor Settlement Agreement and the Staff is authorized to engage in related settlement discussions with the Company and any intervenors.

The order provides that the Staff is required to report to the Georgia PSC by October 5, 2016 with respect to the status of its review and any settlement-related negotiations. If a settlement with the Staff is reached with respect to costs of Plant Vogtle Units 3 and 4, the Georgia PSC will then conduct a hearing to consider whether to approve that settlement. If a settlement with the Staff is not reached, the Georgia PSC will determine how to proceed, including (i) modifying the 2013 Stipulation, (ii) directing the Company to file a request for an amendment to the certificate for Plant Vogtle Units 3 and 4, (iii) issuing a scheduling order to address remaining disputed issues, or (iv) taking any other option within its authority.

The Georgia PSC has approved thirteen VCM reports covering the periods through June 30, 2015, including construction capital costs incurred, which through that date totaled $3.1 billion . On February 26, 2016, the Company filed its fourteenth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2015. The fourteenth VCM report does not include a requested amendment to the certified cost of Plant Vogtle Units 3 and 4. The Company is requesting approval of $160 million of construction capital costs incurred during that period. The Company anticipates to incur average financing costs of approximately $27 million per month from January 2016 until Plant Vogtle Units 3 and 4 are placed in service. The updated in-service capital cost forecast is $5.44 billion and includes costs related to the Contractor Settlement Agreement. Estimated financing costs during the construction period total approximately $2.4 billion . The Company's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.6 billion as of December 31, 2015.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance issues may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

As construction continues, the risk remains that challenges with Contractor performance including fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Future claims by the Contractor or the Company (on behalf of the Vogtle Owners) could arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement and, under the enhanced dispute resolution procedures, may be resolved through litigation after the completion of nuclear fuel load for both units.

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

Income Tax Matters

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 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 50% bonus depreciation is expected to result in approximately $220 million of positive cash flows for the 2015 tax year and approximately $310 million for the 2016 tax year.

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.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

The Company is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

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 the decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, and 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, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. 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 Company previously recorded AROs as a result of state requirements in Georgia which closely align with the requirements of the CCR Rule discussed above. The cost estimates 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 in place or by other methods. 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, 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.

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" and "Nuclear Decommissioning" 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 for each plan 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 has 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 will decrease by approximately $35 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 $10 million or less change in total annual benefit expense and a $141 million or less change in projected obligations.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers* , revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $124 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Notes 6 and 10 to the financial statements for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07) *,* effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the Company. See Notes 2 and 10 to the financial statements for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid income taxes of $34 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 to the financial statements for disclosures impacted by ASU 2015-17.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2015. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing facilities, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2016 through 2018, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation facilities, including Plant Vogtle Units 3 and 4, to maintain existing generation facilities, to add environmental modifications to existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances and capital contributions from Southern Company, as well as by accessing borrowings from financial institutions and borrowings through the FFB. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and nuclear decommissioning trust funds decreased in value as of December 31, 2015 as compared to December 31, 2014. No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated during 2016. The Company funded approximately $5 million to its nuclear decommissioning trust funds in 2015. See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $2.5 billion in 2015, an increase of $154 million from 2014, primarily due to increased fuel cost recovery, partially offset by the timing of vendor payments. Net cash provided from operating activities totaled $2.4 billion in 2014, a decrease of $403 million from 2013, primarily due to the timing of rate recovery for fuel and storm restoration costs, partially offset by higher retail operating revenues and lower fuel inventory additions.

Net cash used for investing activities totaled $1.9 billion, $2.2 billion, and $1.9 billion in 2015, 2014, and 2013, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities; and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years has been provided from operating activities, capital contributions from Southern Company, and the issuance of debt. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information.

Net cash used for financing activities totaled $530 million, $163 million, and $891 million for 2015, 2014, and 2013, respectively. The increase in cash used in 2015 compared to 2014 was primarily due to the redemption and maturity of senior notes in 2015. The decrease in cash used in 2014 compared to 2013 was primarily due to borrowings from the FFB for construction of Plant Vogtle Units 3 and 4, partially offset by FFB loan issuance costs and a reduction in short-term debt. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2015 included an increase of $1.8 billion in total property, plant, and equipment due to gross property additions as described above, an increase in other regulatory assets, deferred of $399 million primarily related to AROs and deferred plant retirement costs, an increase of $615 million in long-term debt, and an increase of $661 million in AROs. See Note 1 to the financial statements for additional information.

The Company's ratio of common equity to total capitalization, including short-term debt, was 49.9% in 2015 and 50.4% in 2014. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described below with respect to the DOE loan guarantees, the Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, external security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approvals, prevailing market conditions, and other factors.

In addition, the Company may make borrowings through a loan guarantee agreement (Loan Guarantee Agreement) between the Company and the DOE, the proceeds of which may be used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Loan Guarantee Agreement (Eligible Project Costs). Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by the Company under a multi-advance credit facility (FFB Credit Facility) among the Company, the DOE, and the FFB. Eligible Project Costs incurred through December 31, 2015 would allow for borrowings of up to $2.3 billion under the FFB Credit Facility, of which the Company has borrowed $2.2 billion . See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement and Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

As of December 31, 2015, the Company's current liabilities exceeded current assets by $772 million primarily due to long-term debt that is due in one year. The Company intends to utilize operating cash flows, as well as FFB borrowings, commercial paper, lines of credit, bank notes, and external securities issuances, as market conditions permit, and equity contributions from Southern Company to fund its short-term capital needs. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs.

At December 31, 2015, the Company had approximately $67 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2015 were $1.75 billion of which $1.73 billion was unused. These credit arrangements expire in 2020.

In August 2015, the Company amended and restated its multi-year credit arrangement, which, among other things, extended the maturity date from 2018 to 2020. The Company increased its borrowing ability by $150 million under its facility maturing in 2020 and terminated its aggregate $150 million facilities maturing in 2016.

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

This bank credit arrangement contains a covenant that limits debt levels and contains a cross acceleration provision to other indebtedness (including guarantee obligations) of the Company. Such cross acceleration provision to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. The Company is currently in compliance with this covenant. This bank credit arrangement does not contain a material adverse change clause at the time of borrowing.

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

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2015 was approximately $872 million. In addition, at December 31, 2015, the Company had $69 million of fixed rate pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months.

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Details of short-term borrowings 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 Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2015:					
Commercial paper	**$ 158**	**0.6%**	**$ 234**	**0.3%**	**$ 678**
Short-term bank debt	**—**	**—%**	**62**	**0.8%**	**250**
Total	**$ 158**	**0.6%**	**$ 296**	**0.4%**	
December 31, 2014:					
Commercial paper	$ 156	0.3%	$ 280	0.2%	$ 703
Short-term bank debt	—	—%	56	0.9%	400
Total	$ 156	0.3%	$ 336	0.3%	
December 31, 2013:					
Commercial paper	$ 647	0.2%	$ 166	0.2%	$ 702
Short-term bank debt	400	0.9%	96	0.9%	400
Total	$ 1,047	0.5%	$ 262	0.5%	

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2015, 2014, and 2013.

The Company believes the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, short-term bank notes, and operating cash flows.

Financing Activities

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

Senior Notes

In April 2015, the Company redeemed $125 million aggregate principal amount of its Series Y 5.80% Senior Notes due April 15, 2035.

In August 2015, the Company's $400 million aggregate principal amount of Series 2012C 0.75% Senior Notes matured.

In November 2015, the Company's $400 million aggregate principal amount of Series 2012D 0.625% Senior Notes matured.

In December 2015, the Company issued $500 million aggregate principal amount of Series 2015A 1.95% Senior Notes due December 1, 2018. The proceeds were used to repay at maturity $250 million aggregate principal amount of the Company's Series Z 5.25% Senior Notes due December 15, 2015, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

Pollution Control Revenue Bonds

In April 2015, the Company purchased and held $65 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 2008. The Company reoffered these bonds to the public in May 2015.

In May 2015, the Company reoffered to the public $104.6 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013, which had been previously purchased and held by the Company since 2013.

In July 2015, $97.925 million aggregate principal amount of the Development Authority of Putnam County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Branch Project), First Series 1996, First Series 1997, Second Series 1997, and First Series 1998 were redeemed.

In August 2015, in connection with optional tenders, the Company repurchased and reoffered to the public $94.6 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2009 and $10 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013.

In November 2015, the Company reoffered to the public $89.2 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), Second Series 2009 and $46 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 1996, which had been previously repurchased and held by the Company since 2010.

DOE Loan Guarantee Borrowings

In June and December 2015, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $600 million and $400 million, respectively. The interest rate applicable to the $600 million principal amount is 3.283% and the interest rate applicable to the $400 million principal amount is 3.072%, both for an interest period that extends to th e final maturity date of February 20, 2044. The proceeds were used to reimburse the Company for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4.

Under the Loan Guarantee Agreement, the Company is subject to customary events of default, as well as cross-defaults to other indebtedness and events of default relating to any failure to make payments under the engineering, procurement, and construction contract, as amended, relating to Plant Vogtle Units 3 and 4 or certain other agreements providing intellectual property rights for Plant Vogtle Units 3 and 4. The Loan Guarantee Agreement also includes events of default specific to the DOE loan guarantee program, including the failure of the Company or Southern Nuclear to comply with requirements of law or DOE loan guarantee program requirements. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information.

Other

In March 2015, the Company entered into a $250 million aggregate principal amount three-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes and the loan was repaid at maturity.

In December 2015, the Company entered into interest rate swaps to hedge exposure to interest rate changes related to existing debt. The notional amount of the swaps totaled $500 million.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, transmission, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at December 31, 2015 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 102
Below BBB- and/or Baa3	$ 1,361

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, 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 August 17, 2015, S&P downgraded the consolidated long-term issuer rating of Southern Company (including the Company) to A- from A. S&P revised its credit rating outlook from negative to stable. Separately, on August 24, 2015, S&P revised its credit rating outlook from stable to negative following the announcement of the proposed merger of a wholly-owned direct subsidiary of Southern Company with and into AGL Resources Inc.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.8 billion of long-term variable interest rate exposure at January 1, 2016 was 1.32%. 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 $18 million at January 1, 2016. See Note 1 to the financial statements under "Financial Instruments" and Note 11 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 a fuel-hedging program implemented per the guidelines of the Georgia PSC. The Company had no material change in market risk exposure for the year ended December 31, 2015 when compared to the December 31, 2014 reporting period.

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

	2015 Changes	2014 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (20)**	$ (16)
Contracts realized or settled:		
Swaps realized or settled	**2**	2
Options realized or settled	**18**	8
Current period changes (*) :		
Swaps	—	(1)
Options	**(13)**	(13)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (13)**	$ (20)

(*) 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 for the years ended December 31 were as follows:

	2015	2014
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	—	4
Commodity – Natural gas options	**50**	42
Total hedge volume	**50**	46

There were no swaps outstanding as of December 31, 2015. The weighted average swap contract cost above market prices was $0.68 per mmBtu as of December 31, 2014. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2015 and 2014, 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, which had a time horizon up to 24 months. On December 15, 2015, the Georgia PSC approved changes to the Company's hedging program allowing it to use an array of derivative instruments within a 48-month time horizon effective January 1, 2016. Hedging gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 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, 2015 were as follows:

	Fair Value Measurements December 31, 2015		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(13)	(10)	(3)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (13)	$ (10)	$ (3)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and 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 11 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $2.5 billion for 2016, $2.4 billion for 2017, and $2.1 billion for 2018. These amounts include expenditures of approximately $0.6 billion, $0.7 billion, and $0.4 billion to continue construction on Plant Vogtle Units 3 and 4 in 2016, 2017, and 2018, respectively. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.3 billion, $0.2 billion, and $0.2 billion for 2016, 2017, and 2018, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure in place or by other methods, and ground water monitoring of ash ponds in accordance with the CCR Rule, which are not reflected in the capital expenditures above as these costs are associated with 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, are estimated to be $0.2 billion, $0.2 billion, and $0.1 billion for the years 2016, 2017, and 2018, 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; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Georgia 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; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for information regarding additional factors that may impact construction expenditures.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, other purchase commitments, and trusts are detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2016	2017-2018	2019-2020	After 2020	Total
			(in millions)		
Long-term debt [(a)] —					
Principal	$ 704	$ 1,197	$ 539	$ 7,833	$ 10,273
Interest	382	715	617	5,205	6,919
Preferred and preference stock dividends [(b)]	17	35	35	—	87
Financial derivative obligations [(c)]	12	3	—	—	15
Operating leases [(d)]	23	30	15	16	84
Capital leases [(d)]	6	14	15	—	35
Purchase commitments —					
Capital [(e)]	2,385	4,113	—	—	6,498
Fuel [(f)]	1,423	1,789	879	6,635	10,726
Purchased power [(g)]	337	633	544	2,803	4,317
Other [(h)]	66	144	148	170	528
Trusts —					
Nuclear decommissioning [(i)]	5	11	11	104	131
Pension and other postretirement benefit plans [(j)]	42	78	—	—	120
Total	$ 5,402	$ 8,762	$ 2,803	$ 22,766	$ 39,733

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information. 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, 2016, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).
(b) Preferred and preference stock do not mature; therefore, amounts provided are for the next five years only.
(c) Includes derivative liabilities related to cash flow hedges of forecasted debt, as well as energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.
(d) Excludes PPAs that are accounted for as leases and included in "Purchased power."
(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected in "Fuel" and "Other," respectively. At December 31, 2015, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.
(f) Includes commitments to purchase coal, nuclear fuel, 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, 2015.
(g) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. Includes a total of $304 million of biomass PPAs that is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Renewables Development" herein for additional information.
(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.
(i) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP . See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.
(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 2015 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, 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 , postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects and changing fuel sources, filings with state and federal regulatory authorities, impact of the PATH Act, estimated sales and purchases under power sale and purchase agreements, 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 legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, 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, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including , without limitation, IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the 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 and construction 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, contractor or supplier delay, non-performance under construction 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 Georgia 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 and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- 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 currency exchange rates, counterparty performance, and the economy in general , as well as potential impacts on the benefits of the DOE loan guarantees;
- 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, 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.

STATEMENTS OF INCOME
For the Years Ended December 31, 2015 , 2014 , and 2013
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	2015	2014	2013
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 7,727**	$ 8,240	$ 7,620
Wholesale revenues, non-affiliates	**215**	335	281
Wholesale revenues, affiliates	**20**	42	20
Other revenues	**364**	371	353
Total operating revenues	**8,326**	8,988	8,274
Operating Expenses:			
Fuel	**2,033**	2,547	2,307
Purchased power, non-affiliates	**289**	287	224
Purchased power, affiliates	**575**	701	660
Other operations and maintenance	**1,844**	1,902	1,654
Depreciation and amortization	**846**	846	807
Taxes other than income taxes	**391**	409	382
Total operating expenses	**5,978**	6,692	6,034
Operating Income	**2,348**	2,296	2,240
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(363)**	(348)	(361)
Other income (expense), net	**61**	23	35
Total other income and (expense)	**(302)**	(325)	(326)
Earnings Before Income Taxes	**2,046**	1,971	1,914
Income taxes	**769**	729	723
Net Income	**1,277**	1,242	1,191
Dividends on Preferred and Preference Stock	**17**	17	17
Net Income After Dividends on Preferred and Preference Stock	**$ 1,260**	$ 1,225	$ 1,174

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2015 , 2014 , and 2013
Georgia Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Net Income	**$ 1,277**	$ 1,242	$ 1,191
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(6), $(3), and $-, respectively	**(9)**	(5)	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**2**	2	2
Total other comprehensive income (loss)	**(7)**	(3)	2
Comprehensive Income	**$ 1,270**	$ 1,239	$ 1,193

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2015 , 2014 , and 2013
Georgia Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Activities:			
Net income	$ 1,277	$ 1,242	$ 1,191
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	1,029	1,019	979
Deferred income taxes	173	352	476
Allowance for equity funds used during construction	(40)	(45)	(30)
Retail fuel cost over-recovery — long-term	106	(44)	(123)
Pension, postretirement, and other employee benefits	40	19	66
Pension and postretirement funding	(7)	(156)	(8)
Other, net	(59)	39	38
Changes in certain current assets and liabilities —			
-Receivables	187	(248)	(58)
-Fossil fuel stock	37	303	250
-Prepaid income taxes	89	(216)	(17)
-Other current assets	(62)	(37)	40
-Accounts payable	(259)	16	67
-Accrued taxes	25	17	(14)
-Accrued compensation	(17)	62	(37)
-Retail fuel cost over-recovery — short-term	10	(14)	(49)
-Other current liabilities	(12)	54	(5)
Net cash provided from operating activities	2,517	2,363	2,766
Investing Activities:			
Property additions	(2,091)	(2,023)	(1,743)
Investment in restricted cash from pollution control bonds	—	—	(89)
Distribution of restricted cash from pollution control bonds	—	—	89
Nuclear decommissioning trust fund purchases	(985)	(671)	(706)
Nuclear decommissioning trust fund sales	980	669	705
Cost of removal, net of salvage	(71)	(65)	(59)
Change in construction payables, net of joint owner portion	217	(54)	(67)
Prepaid long-term service agreements	(66)	(70)	(18)
Sale of property	70	7	7
Other investing activities	2	1	(9)
Net cash used for investing activities	(1,944)	(2,206)	(1,890)
Financing Activities:			
Increase (decrease) in notes payable, net	2	(891)	1,047
Proceeds —			
Capital contributions from parent company	62	549	37
Pollution control revenue bonds issuances and remarketings	409	40	194
Senior notes issuances	500	—	850
FFB loan	1,000	1,200	—
Short-term borrowings	250	—	—
Redemptions and repurchases —			
Pollution control revenue bonds	(268)	(37)	(298)
Senior notes	(1,175)	—	(1,775)
Short-term borrowings	(250)	—	—
Payment of preferred and preference stock dividends	(17)	(17)	(17)
Payment of common stock dividends	(1,034)	(954)	(907)

FFB loan issuance costs	**—**	(49)	(5)
Other financing activities	**(9)**	(4)	(17)
Net cash used for financing activities	**(530)**	(163)	(891)
Net Change in Cash and Cash Equivalents	**43**	(6)	(15)
Cash and Cash Equivalents at Beginning of Year	**24**	30	45
Cash and Cash Equivalents at End of Year	**$ 67**	$ 24	$ 30
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $16, $18, and $14 capitalized, respectively)	**$ 353**	$ 319	$ 344
Income taxes (net of refunds)	**506**	507	298
Noncash transactions —			
Accrued property additions at year-end	**387**	154	208
Capital lease obligation	**149**	—	—

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

BALANCE SHEETS
At December 31, 2015 and 2014
Georgia Power Company 2015 Annual Report

Assets	**2015**	2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 67**	$ 24
Receivables —		
Customer accounts receivable	**541**	553
Unbilled revenues	**188**	201
Joint owner accounts receivable	**227**	121
Other accounts and notes receivable	**57**	61
Affiliated companies	**18**	18
Accumulated provision for uncollectible accounts	**(2)**	(6)
Income taxes receivable, current	**114**	—
Fossil fuel stock, at average cost	**402**	439
Materials and supplies, at average cost	**449**	438
Vacation pay	**91**	91
Prepaid income taxes	**156**	244
Other regulatory assets, current	**123**	136
Other current assets	**92**	74
Total current assets	**2,523**	2,394
Property, Plant, and Equipment:		
In service	**31,841**	31,083
Less accumulated provision for depreciation	**10,903**	11,222
Plant in service, net of depreciation	**20,938**	19,861
Other utility plant, net	**171**	211
Nuclear fuel, at amortized cost	**572**	563
Construction work in progress	**4,775**	4,031
Total property, plant, and equipment	**26,456**	24,666
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**64**	58
Nuclear decommissioning trusts, at fair value	**775**	789
Miscellaneous property and investments	**43**	38
Total other property and investments	**882**	885
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**679**	698
Deferred under recovered regulatory clause revenues	**—**	197
Other regulatory assets, deferred	**2,152**	1,753
Other deferred charges and assets	**173**	279
Total deferred charges and other assets	**3,004**	2,927
Total Assets	**$ 32,865**	$ 30,872

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

BALANCE SHEETS
At December 31, 2015 and 2014
Georgia Power Company 2015 Annual Report

Liabilities and Stockholder's Equity	**2015**	2014
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 712**	$ 1,150
Notes payable	**158**	156
Accounts payable —		
Affiliated	**411**	451
Other	**750**	555
Customer deposits	**264**	253
Accrued taxes —		
Accrued income taxes	**12**	—
Other accrued taxes	**325**	332
Accrued interest	**99**	96
Accrued vacation pay	**62**	63
Accrued compensation	**142**	153
Asset retirement obligations, current	**179**	32
Liabilities from risk management activities	**12**	32
Other regulatory liabilities, current	**16**	21
Over recovered regulatory clause revenues, current	**10**	—
Other current liabilities	**143**	172
Total current liabilities	**3,295**	3,466
Long-Term Debt (See accompanying statements)	**9,616**	8,563
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**5,627**	5,474
Deferred credits related to income taxes	**105**	106
Accumulated deferred investment tax credits	**204**	196
Employee benefit obligations	**949**	903
Asset retirement obligations, deferred	**1,737**	1,223
Other cost of removal obligations	**16**	46
Other deferred credits and liabilities	**331**	208
Total deferred credits and other liabilities	**8,969**	8,156
Total Liabilities	**21,880**	20,185
Preferred Stock (See accompanying statements)	**45**	45
Preference Stock (See accompanying statements)	**221**	221
Common Stockholder's Equity (See accompanying statements)	**10,719**	10,421
Total Liabilities and Stockholder's Equity	**$ 32,865**	$ 30,872
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2015 and 2014
Georgia Power Company 2015 Annual Report

	2015	2014	2015	2014
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
Variable rates (0.76% to 0.83% at 1/1/16) due 2016	**$ 450**	$ 450		
0.625% to 5.25% due 2015	**—**	1,050		
3.00% due 2016	**250**	250		
5.70% due 2017	**450**	450		
1.95% to 5.40% due 2018	**747**	250		
4.25% due 2019	**502**	500		
2.85% to 5.95% due 2022-2043	**3,850**	3,975		
Total long-term notes payable	**6,249**	6,925		
Other long-term debt —				
Pollution control revenue bonds —				
0.85% to 4.00% due 2022-2049	**952**	818		
Variable rates (0.03% to 0.04% at 1/1/15) due 2015	**—**	98		
Variable rate (0.22% at 1/1/16) due 2016	**4**	4		
Variable rates (0.10% to 0.27% at 1/1/16) due 2022-2053	**868**	763		
FFB loans —				
3.00% to 3.86% due 2020	**37**	20		
3.00% to 3.86% due 2021-2044	**2,163**	1,180		
Total other long-term debt	**4,024**	2,883		
Capitalized lease obligations	**183**	40		
Unamortized debt premium (discount), net	**(10)**	(11)		
Unamortized debt issuance expense	**(118)**	(124)		
Total long-term debt (annual interest requirement — $382 million)	**10,328**	9,713		
Less amount due within one year	**712**	1,150		
Long-term debt excluding amount due within one year	**9,616**	8,563	**46.7%**	44.5%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value — 6.125%				
Authorized — 50,000,000 shares				
Outstanding — 1,800,000 shares	**45**	45		
Non-cumulative preference stock				
$100 par value — 6.50%				
Authorized — 15,000,000 shares				
Outstanding — 2,250,000 shares	**221**	221		
Total preferred and preference stock (annual dividend requirement — $17 million)	**266**	266	**1.3**	1.4
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 9,261,500 shares	**398**	398		
Paid-in capital	**6,275**	6,196		
Retained earnings	**4,061**	3,835		
Accumulated other comprehensive loss	**(15)**	(8)		
Total common stockholder's equity	**10,719**	10,421	**52.0**	54.1
Total Capitalization	**$ 20,601**	$ 19,250	**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, 2015 , 2014 , and 2013
Georgia Power Company 2015 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2012	9	$ 398	$ 5,585	$ 3,297	$ (7)	$ 9,273
Net income after dividends on preferred and preference stock	—	—	—	1,174	—	1,174
Capital contributions from parent company	—	—	48	—	—	48
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(907)	—	(907)
Other	—	—	—	1	—	1
Balance at December 31, 2013	9	398	5,633	3,565	(5)	9,591
Net income after dividends on preferred and preference stock	—	—	—	1,225	—	1,225
Capital contributions from parent company	—	—	563	—	—	563
Other comprehensive income (loss)	—	—	—	—	(3)	(3)
Cash dividends on common stock	—	—	—	(954)	—	(954)
Other	—	—	—	(1)	—	(1)
Balance at December 31, 2014	**9**	**398**	**6,196**	**3,835**	**(8)**	**10,421**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**1,260**	**—**	**1,260**
Capital contributions from parent company	**—**	**—**	**79**	**—**	**—**	**79**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**(7)**	**(7)**
Cash dividends on common stock	**—**	**—**	**—**	**(1,034)**	**—**	**(1,034)**
Balance at December 31, 2015	**9**	**$ 398**	**$ 6,275**	**$ 4,061**	**$ (15)**	**$ 10,719**

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

NOTES TO FINANCIAL STATEMENTS
Georgia Power Company 2015 Annual Report

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NOTES (continued)
Georgia Power Company 2015 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional operating companies, as well as Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public, and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Hatch and Plant Vogtle.

The equity method is used for subsidiaries in which the Company has significant influence but does not control.

The Company is subject to regulation by the FERC and the Georgia 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.

In June 2015, the Company identified an error affecting the billing to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing from January 1, 2013 to June 30, 2015. In the second quarter 2015, the Company recorded an out of period adjustment of approximately $75 million to decrease retail revenues, resulting in a decrease to net income of approximately $47 million . The Company evaluated the effects of this error on the interim and annual periods that included the billing error, as well as the current period. Based on an analysis of qualitative and quantitative factors, the Company determined the error was not material to any affected period and, therefore, an amendment of previously filed financial statements was not required.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers* , revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $124 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Notes 6 and 10 for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07) , effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the

Company. See Notes 2 and 10 for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid income taxes of $34 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 for disclosures impacted by ASU 2015-17.

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 $585 million in 2015 , $555 million in 2014 , and $504 million in 2013 . 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 Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business, operations, and construction management. Costs for these services amounted to $681 million in 2015 , $643 million in 2014 , and $555 million in 2013 .

The Company has entered into several PPAs with Southern Power for capacity and energy. Expenses associated with these PPAs were $179 million , $144 million , and $136 million in 2015 , 2014 , and 2013 , respectively. Additionally, the Company had $15 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2015 and 2014 . See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has a joint ownership agreement with Gulf Power under which Gulf Power owns a 25% portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $12 million in 2015 , $9 million in 2014 , and $10 million in 2013 . See Note 4 for additional information.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2015 , 2014 , or 2013 .

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

Regulatory Assets and Liabilities

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

NOTES (continued)
Georgia Power Company 2015 Annual Report

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

	2015	2014	Note
	(in millions)		
Retiree benefit plans	$ 1,307	$ 1,325	(a, j)
Deferred income tax charges	653	668	(b, j)
Loss on reacquired debt	150	163	(c, j)
Asset retirement obligations	411	108	(b, j)
Vacation pay	91	91	(d, j)
Cancelled construction projects	56	67	(e)
Remaining net book value of retired assets	171	29	(f)
Storm damage reserves	92	98	(g)
Other regulatory assets	140	153	(h)
Other cost of removal obligations	(31)	(60)	(b)
Deferred income tax credits	(105)	(106)	(b, j)
Other regulatory liabilities	(2)	(7)	(i, j)
Total regulatory assets (liabilities), net	$ 2,933	$ 2,529	

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) 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 70 years . Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2015, other cost of removal obligations included $14 million that will be amortized over the twelve months ending December 31, 2016 in accordance with the three-year amortization period approved in the Company's 2013 ARP.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which currently does not exceed 38 years .

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

(e) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements are being amortized as approved by the Georgia PSC over periods not exceeding nine years or through 2022.

(f) Amortized as approved by the Georgia PSC over periods not exceeding 10 years or through 2024. Amortization of obsolete inventories will be determined by the Georgia PSC in the 2016 base rate case.

(g) Recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding six years or through 2019.

(h) Comprised of several components including deferred nuclear outages, environmental remediation, Medicare subsidy deferred income tax charges, fuel hedging losses, building lease, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding 12 years or through 2022.

(i) Comprised primarily of fuel-hedging gains, which upon final settlement are refunded through the Company's fuel cost recovery mechanism.

(j) Generally not earning a return as they are excluded from rate base or are offset in rate base by a corresponding asset or liability.

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" for additional information.

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel. See Note 3 under "Retail Regulatory Matters – Nuclear Waste Fund Fee" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Federal ITCs utilized are deferred and amortized to income as a credit to reduce depreciation over the average life of the related property. State ITCs and other credits are recognized in the period in which the credits are claimed on the state income tax return. The Company had state investment and other tax credit carryforwards totaling $318 million , which will expire between 2018 and 2026 and are expected to be fully utilized by 2022.

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 cost of equity and debt funds used during construction.

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

	2015	2014
	(in millions)	
Generation	**$ 15,386**	$ 15,201
Transmission	**5,355**	5,086
Distribution	**9,151**	8,913
General	**1,921**	1,855
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 31,841**	$ 31,083

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 as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch Units 1 and 2, respectively.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.7% in 2015 , 2.7% in 2014 , and 3.0% in 2013 . Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Under the terms of the Company's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP) and the 2013 ARP, the Company amortized approximately $31 million in 2013 and $14 million in each of 2014 and 2015 of its remaining regulatory liability related to other cost of removal obligations.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) 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 Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The ARO liability primarily relates to the Company's ash ponds, landfills, and gypsum cells that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA on April 17, 2015 (CCR Rule). In addition, the Company has retirement obligations related to decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. 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 Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

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

	2015	2014
	(in millions)	
Balance at beginning of year	**$ 1,255**	$ 1,222
Liabilities incurred	**6**	9
Liabilities settled	**(30)**	(12)
Accretion	**56**	53
Cash flow revisions	**629**	(17)
Balance at end of year	**$ 1,916**	$ 1,255

The increase in cash flow revisions in 2015 is primarily related to changes to the Company's ash ponds, landfill, and gypsum cell ARO closure dollar and timing estimates associated with the CCR Rule and revisions to the nuclear decommissioning AROs based on the latest decommissioning study. In preparation for the Company's next rate case, and as a part of the Company's three -year ARO update cycle, new closure estimates were developed for ash ponds, landfills, gypsum cells, nuclear decommissioning, and asbestos AROs. The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2015 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 in place or by other methods. 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, 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.

The 2014 decrease in cash flow revisions is primarily related to settled AROs for asbestos remediation.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the IRS. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2015 and 2014 , approximately $76 million and $51 million , respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $78 million and $52 million at December 31, 2015 and 2014 , respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2015 , investment securities in the Funds totaled $775 million , consisting of equity securities of $296 million , debt securities of $463 million , and $16 million of other securities. At December 31, 2014 , investment securities in the Funds totaled $789 million , consisting of equity securities of $303 million , debt securities of $475 million , and $11 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $980 million , $669 million , and $705 million in 2015 , 2014 , and 2013 , respectively, all of which were reinvested. For 2015 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $3 million , which included $26 million related to unrealized losses on securities held in the Funds at December 31, 2015 . For 2014 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $44 million , which included an immaterial amount related to unrealized gains and losses on securities held in the Funds at December 31, 2014 . For 2013 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $61 million , which included $34 million related to unrealized gains on securities held in the Funds at December 31, 2013 . While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning are based on the most current study performed in 2015. The site study costs and external trust funds for decommissioning as of December 31, 2015 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2075	2079
	(in millions)	
Site study costs:		
Radiated structures	$ 678	$ 568
Spent fuel management	160	147
Non-radiated structures	64	89
Total site study costs	$ 902	$ 804
External trust funds	$ 487	$ 288

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved annual decommissioning cost through 2016 for ratemaking of $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4% . The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs.

Allowance for Funds Used During Construction

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 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 calculating taxable income. For the years 2015 , 2014 , and 2013 , the average AFUDC rates were 6.5% , 5.6% , and 5.3% , respectively, and AFUDC capitalized was $56 million , $62 million , and $44 million , respectively. AFUDC, net of income taxes, was 3.9% , 4.6% , and 3.3% of net income after dividends on preferred and preference stock for 2015 , 2014 , and 2013 , respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information on the inclusion of construction costs related to Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011.

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.

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Beginning January 1, 2014, the Company is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. As of December 31, 2015 and December 31, 2014 , the balance in the regulatory asset related to storm damage was $92 million and $98 million , respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $62 million and $68 million included in other regulatory assets, deferred, respectively. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs. As a result of the regulatory treatment, costs related to storms are generally not expected to have a material impact on the Company's earnings.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. In December 2013, the Georgia PSC approved the 2013 ARP including the recovery of approximately $2 million annually through the environmental compliance cost recovery (ECCR) tariff from 2014 through 2016. The Company recovered approximately $3 million annually through the ECCR tariff from 2011 through 2013 under the 2010 ARP. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's earnings. As of December 31, 2015 , the balance of the environmental remediation liability was $29 million , with approximately $2 million included in other regulatory assets, current and approximately $30 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" for additional information.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, and oil, as well as transportation and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. 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, and electricity purchases and sales. 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 10 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 fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts 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 income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2015 .

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

Comprehensive Income

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

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2016 . 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 Georgia PSC and the FERC. For the year ending December 31, 2016 , other postretirement trust contributions are expected to total approximately $14 million .

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:	2015	2014	2013
Pension plans			
Discount rates – interest costs	**4.18%**	5.02%	4.27%
Discount rates – service costs	**4.49**	5.02	4.27
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**3.59**	3.59	3.59
Other postretirement benefit plans			
Discount rate – interest costs	**4.03%**	4.85%	4.04%
Discount rate – service costs	**4.39**	4.85	4.04
Expected long-term return on plan assets	**6.48**	6.75	6.74
Annual salary increase	**3.59**	3.59	3.59

Assumptions used to determine benefit obligations:	2015	2014
Pension plans		
Discount rate	**4.65%**	4.18%
Annual salary increase	**4.46**	3.59
Other postretirement benefit plans		
Discount rate	**4.49%**	4.03%
Annual salary increase	**4.46**	3.59

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

For purposes of its December 31, 2015 measurement date, the Company adopted new mortality tables for its pension and other postretirement benefit plans, which reflect decreased life expectancies in the U.S. The adoption of new mortality tables reduced the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $66 million and $17 million , respectively.

NOTES (continued)
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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, 2015 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2024
Post-65 medical	5.50	4.50	2024
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, 2015 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 58	$ (50)
Service and interest costs	2	(2)

Pension Plans

The total accumulated benefit obligation for the pension plans was $3.3 billion at December 31, 2015 and $3.5 billion at December 31, 2014 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 3,781**	$ 3,116
Service cost	**73**	62
Interest cost	**154**	153
Benefits paid	**(188)**	(149)
Actuarial loss (gain)	**(205)**	599
Balance at end of year	**3,615**	3,781
Change in plan assets		
Fair value of plan assets at beginning of year	**3,383**	3,085
Actual return (loss) on plan assets	**(13)**	285
Employer contributions	**14**	162
Benefits paid	**(188)**	(149)
Fair value of plan assets at end of year	**3,196**	3,383
Accrued liability	**$ (419)**	$ (398)

At December 31, 2015 , the projected benefit obligations for the qualified and non-qualified pension plans were $3.5 billion and $151 million , respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's pension plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 1,076**	$ 1,102
Current liabilities, other	**(13)**	(12)
Employee benefit obligations	**(406)**	(386)

Presented below are the amounts included in regulatory assets at December 31, 2015 and 2014 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 2016 .

	2015	2014	Estimated Amortization in 2016
		(in millions)	
Prior service cost	**$ 8**	$ 17	**$ 5**
Net (gain) loss	**1,068**	1,085	**55**
Regulatory assets	**$ 1,076**	$ 1,102	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 1,102**	$ 610
Net (gain) loss	**59**	543
Reclassification adjustments:		
Amortization of prior service costs	**(9)**	(10)
Amortization of net gain (loss)	**(76)**	(41)
Total reclassification adjustments	**(85)**	(51)
Total change	**(26)**	492
Ending balance	**$ 1,076**	$ 1,102

Components of net periodic pension cost were as follows:

	2015	2014	2013
		(in millions)	
Service cost	**$ 73**	$ 62	$ 69
Interest cost	**154**	153	138
Expected return on plan assets	**(251)**	(228)	(212)
Recognized net loss	**76**	41	74
Net amortization	**9**	10	10
Net periodic pension cost	**$ 61**	$ 38	$ 79

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.

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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, 2015 , estimated benefit payments were as follows:

		Benefit Payments
		(in millions)
2016	$	168
2017		176
2018		183
2019		189
2020		197
2021 to 2025		1,085

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

		2015		2014
		(in millions)		
Change in benefit obligation				
Benefit obligation at beginning of year	**$**	**864**	$	723
Service cost		**7**		6
Interest cost		**34**		34
Benefits paid		**(45)**		(44)
Actuarial loss (gain)		**(22)**		142
Plan amendment		**12**		—
Retiree drug subsidy		**4**		3
Balance at end of year		**854**		864
Change in plan assets				
Fair value of plan assets at beginning of year		**395**		407
Actual return (loss) on plan assets		**(6)**		21
Employer contributions		**10**		8
Benefits paid		**(41)**		(41)
Fair value of plan assets at end of year		**358**		395
Accrued liability	**$**	**(496)**	$	(469)

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's other postretirement benefit plans consist of the following:

		2015		2014
		(in millions)		
Other regulatory assets, deferred	**$**	**223**	$	213
Employee benefit obligations		**(496)**		(469)

NOTES (continued)
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Presented below are the amounts included in regulatory assets at December 31, 2015 and 2014 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2016 .

	2015	2014	Estimated Amortization in 2016
		(in millions)	
Prior service cost	**$ 8**	$ (5)	**$ 1**
Net (gain) loss	**215**	218	**9**
Regulatory assets	**$ 223**	$ 213	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 213**	$ 69
Net (gain) loss	**9**	146
Change in prior service costs	**12**	—
Reclassification adjustments:		
Amortization of net gain (loss)	**(11)**	(2)
Total change	**10**	144
Ending balance	**$ 223**	$ 213

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

	2015	2014	2013
		(in millions)	
Service cost	**$ 7**	$ 6	$ 7
Interest cost	**34**	34	31
Expected return on plan assets	**(24)**	(25)	(24)
Net amortization	**11**	2	12
Net periodic postretirement benefit cost	**$ 28**	$ 17	$ 26

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)	
2016	$ 53	$ (4)	$ 49
2017	55	(4)	51
2018	58	(5)	53
2019	59	(5)	54
2020	60	(5)	55
2021 to 2025	305	(28)	277

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. 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, 2015 and 2014 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2015**	2014
Pension plan assets:			
Domestic equity	26%	**30%**	30%
International equity	25	**23**	23
Fixed income	23	**23**	27
Special situations	3	**2**	1
Real estate investments	14	**16**	14
Private equity	9	**6**	5
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	40%	**34%**	38%
International equity	21	**27**	26
Domestic fixed income	23	**25**	24
Global fixed income	9	**8**	7
Special situations	1	**—**	—
Real estate investments	4	**4**	4
Private equity	2	**2**	1
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.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.

- ***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, 2015 and 2014 . 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.
- ***TOLI.*** Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

NOTES (continued)
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The fair values of pension plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 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*	$ 565	$ 236	$ —	$ —	$ 801
International equity*	412	343	—	—	755
Fixed income:					
U.S. Treasury, government, and agency bonds	—	157	—	—	157
Mortgage- and asset-backed securities	—	69	—	—	69
Corporate bonds	—	394	—	—	394
Pooled funds	—	173	—	—	173
Cash equivalents and other	—	50	—	—	50
Real estate investments	103	—	—	421	524
Private equity	—	—	—	220	220
Total	$ 1,080	$ 1,422	$ —	$ 641	$ 3,143

* 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.

NOTES (continued)
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As of December 31, 2014:	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*	$ 595	$ 246	$ —	$ —	$ 841
International equity*	373	344	—	—	717
Fixed income:					
U.S. Treasury, government, and agency bonds	—	244	—	—	244
Mortgage- and asset-backed securities	—	66	—	—	66
Corporate bonds	—	398	—	—	398
Pooled funds	—	179	—	—	179
Cash equivalents and other	1	230	—	—	231
Real estate investments	102	—	—	391	493
Private equity	—	—	—	199	199
Total	$ 1,071	$ 1,707	$ —	$ 590	$ 3,368
Liabilities:					
Derivatives	$ (1)	$ —	$ —	$ —	$ (1)
Total	$ 1,070	$ 1,707	$ —	$ 590	$ 3,367

* 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.

NOTES (continued)
Georgia Power Company 2015 Annual Report

The fair values of other postretirement benefit plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 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*	$ 30	$ 36	$ —	$ —	$ 66
International equity*	12	41	—	—	53
Fixed income:					
U.S. Treasury, government, and agency bonds	—	5	—	—	5
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	12	—	—	12
Pooled funds	—	30	—	—	30
Cash equivalents and other	10	6	—	—	16
Trust-owned life insurance	—	158	—	—	158
Real estate investments	3	—	—	12	15
Private equity	—	—	—	7	7
Total	$ 55	$ 290	$ —	$ 19	$ 364

* 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, 2014:	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*	$ 53	$ 40	$ —	$ —	$ 93
International equity*	11	45	—	—	56
Fixed income:					
U.S. Treasury, government, and agency bonds	—	7	—	—	7
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	12	—	—	12
Pooled funds	—	29	—	—	29
Cash equivalents and other	8	11	—	—	19
Trust-owned life insurance	—	162	—	—	162
Real estate investments	3	—	—	12	15
Private equity	—	—	—	6	6
Total	$ 75	$ 308	$ —	$ 18	$ 401

* 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 2015 , 2014 , and 2013 were $26 million , $25 million , and $24 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has 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. See Note 1 under "Environmental Remediation Recovery" for additional information.

The Company has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a site in Brunswick, Georgia on the CERCLA National Priorities List. The PRPs at the Brunswick site have completed a removal action as ordered by the EPA. Additional response actions at this site are anticipated. In September 2015, the Company entered into an allocation agreement with another PRP, under which that PRP will be responsible (as between the Company and that PRP) for paying and performing certain investigation, assessment, remediation, and other incidental activities at the Brunswick site. Assessment and potential cleanup of other sites are anticipated.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of the Company's regulatory treatment for environmental remediation expenses described in Note 1 under "Environmental Remediation Recovery," these matters are not expected to have a material impact on the Company's financial statements.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with the Company that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Hatch and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

In December 2014, the Court of Federal Claims entered a judgment in favor of the Company in its spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. On March 19, 2015, the Company recovered approximately $18 million , based on its ownership interests. In March 2015, the Company credited the award to accounts where the original costs were charged and reduced rate base, fuel, and cost of service for the benefit of customers.

In March 2014, the Company filed additional lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2015 for any potential recoveries from the additional lawsuits. The final outcome of these matters cannot be determined at this time; however, no material impact on the Company's net income is expected.

On-site dry spent fuel storage facilities are operational at Plant Vogtle Units 1 and 2 and Plant Hatch. Facilities can be expanded to accommodate spent fuel through the expected life of each plant.

FERC Matters

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 operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional 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 operating companies and in some adjacent areas. The FERC directed the traditional 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 operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Rate Plans

In 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors.

In January 2014, in accordance with the 2013 ARP, the Company increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million ; (2) ECCR tariff by approximately $25 million ; (3) Demand-Side Management (DSM) tariffs by approximately $1 million ; and (4) Municipal Franchise Fee (MFF) tariff by approximately $4 million , for a total increase in base revenues of approximately $110 million .

On February 19, 2015 , in accordance with the 2013 ARP, the Georgia PSC approved an increase to tariffs effective January 1, 2015 as follows: (1) traditional base tariff rates by approximately $107 million ; (2) ECCR tariff by approximatel y $23 million ; (3) DSM tariffs by approximately $3 million ; and (4) MFF tariff by approximately $3 million , for a total increase in base revenues of approximately $136 million .

On December 16, 2015, in accordance with the 2013 ARP, the Georgia PSC approved an increase to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million ; (2) ECCR tariff by approximately $75 million ; (3) DSM tariffs by approximately $3 million ; and (4) MFF tariff by approximately $13 million , for a total increase in base revenues of approximately $140 million .

Under the 2013 ARP, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00% . Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, the Company's retail ROE exceeded 12.00% , and the Company will refund to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, the Company's retail ROE was within the allowed retail ROE range.

The Company is required to file a general base rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plan

To comply with the April 16, 2015 effective date of the MATS rule, Plant Branch Units 1, 3, and 4 (1,266 MWs) , Plant Yates Units 1 through 5 (579 MWs) , and Plant McManus Units 1 and 2 (122 MWs) were retired and operations were discontinued at Plant Mitchell Unit 3 (155 MWs) by April 15, 2015, and Plant Kraft Units 1 through 4 (316 MWs) were retired on October 13, 2015. The switch to natural gas as the primary fuel was completed at Plant Yates Units 6 and 7 by June 2015 and at Plant Gaston Units 1 through 4 by December 2015.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years ending December 2022 and the amortization of the remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024.

On January 29, 2016, the Company filed its triennial IRP (2016 IRP). The filing included a request to decertify Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs) upon approval of the 2016 IRP. The 2016 IRP also reflects that the Company exercised its contractual option to sell its 33% ownership interest in the Intercession City unit (143 MWs total capacity) to Duke Energy Florida, Inc. See Note 4 for additional information.

In the 2016 IRP, the Company requested reclassification of the remaining net book value of Plant Mitchell Unit 3, as of its retirement date, to a regulatory asset to be amortized over a period equal to the unit's remaining useful life. The Company also requested that the Georgia PSC approve the deferral of the cost associated with materials and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a period deemed appropriate by the Georgia PSC.

The decertification and retirement of these units are not expected to have a material impact on the Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's orders in the 2016 IRP and next general base rate case.

Additionally, the 2016 IRP included a Renewable Energy Development Initiative requesting to procure up to 525 MWs of renewable resources utilizing market-based prices established through a competitive bidding process to expand the Company’s existing renewable initiatives, including the Advanced Solar Initiative.

A decision from the Georgia PSC on the 2016 IRP is expected in the third quarter 2016. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved a reduction in the Company's total annual billings of approximately $567 million effective June 1, 2012, with an additional $122 million reduction effective January 1, 2013 through June 1, 2014. Under an Interim Fuel Rider, the Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million . The

Company's fuel cost recovery includes costs associated with a natural gas hedging program, as approved by the Georgia PSC in 2015, allowing it to use an array of derivative instruments within a 48 -month time horizon effective January 1, 2016. See Note 11 under "Energy-Related Derivatives" for additional information. On December 15, 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016.

The Company's over recovered fuel balance totaled approximately $116 million at December 31, 2015 and is included in current liabilities and other deferred liabilities. At December 31, 2014 , the Company's under recovered fuel balance totaled approximately $199 million and was included in current assets and other deferred charges and assets.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (Westinghouse and Stone & Webster, Inc., collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not occurred), with maximum additional capital costs under this provision attributable to the Company (based on the Company's ownership interest) of approximately $114 million . Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7% .

On December 31, 2015, Westinghouse acquired Stone & Webster, Inc. from CB&I (Acquisition). In connection with the Acquisition, Stone & Webster, Inc. changed its name to WECTEC Global Project Services Inc. (WECTEC). Certain obligations of Westinghouse and Stone & Webster, Inc. have been guaranteed by Toshiba Corporation, Westinghouse's parent company, and CB&I's The Shaw Group Inc., respectively. Subject to the consent of the DOE, in connection with the Acquisition and pursuant to the settlement agreement described below, the guarantee of The Shaw Group Inc. will be terminated. The guarantee of Toshiba Corporation remains in place. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement. Additionally, on January 13, 2016, as a result of recent credit rating downgrades of Toshiba Corporation, Westinghouse provided the Vogtle Owners with letters of credit in an aggregate amount of $900 million in accordance with, and subject to adjustment under, the terms of the Vogtle 3 and 4 Agreement.

The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events.

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges may arise as construction proceeds.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved an initial NCCR tariff of approximately $223 million effective January 1, 2011, as well as increases to the NCCR tariff of approximately $35 million , $50 million , $60 million , $27 million , and $19 million effective January 1, 2012, 2013, 2014, 2015, and 2016, respectively.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected construction capital costs to be borne by the Company increase by 5% above the certified cost or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. In February 2013, the Company requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 (from April 2016) and the fourth quarter 2018 (from April 2017) for Plant Vogtle Units 3 and 4, respectively. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between the Company and the Georgia PSC Staff (Staff) to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and the Company.

On April 15, 2015, the Georgia PSC issued a procedural order in connection with the twelfth VCM report, which included a requested amendment (Requested Amendment) to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 (second quarter of 2019 and second quarter of 2020, respectively) as well as additional estimated Vogtle Owner's costs, of approximately $10 million per month, including property taxes, oversight costs, compliance costs, and other operational readiness costs to include the estimated Vogtle Owner's costs associated with the proposed 18 - month Contractor delay and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion . Pursuant to the Georgia PSC's procedural order, the Georgia PSC deemed the Requested Amendment unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation. The Georgia PSC recognized that the certified cost and the 2013 Stipulation do not constitute a cost recovery cap. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by the Company in excess of the certified amount will be included in rate base, provided the Company shows the costs to be reasonable and prudent. Financing costs up to the certified amount will be collected through the NCCR tariff until the units are placed in service and contemplated in a general base rate case, while financing costs on any construction-related costs in excess of the $4.4 billion certified amount are expected to be recovered through AFUDC.

In 2012, the Vogtle Owners and the Contractor commenced litigation regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The Contractor also asserted that it was entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. In May 2014, the Contractor filed an amended claim alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. In June 2015, the Contractor updated its estimated damages to an aggregate (based on the Company's ownership interest) of approximately $714 million (in 2015 dollars). The case was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation).

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including the Vogtle Construction Litigation. Effective December 31, 2015, the Company, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to match the current estimated in-service dates of June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will now commence from the current estimated nuclear fuel loading date for each unit, which is December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4, rather than the original guaranteed substantial completion dates under the Vogtle 3 and 4 Agreement; and (v) provide that the Company, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million , of which approximately $120 million has been paid previously under the dispute resolution procedures of the Vogtle 3 and 4 Agreement. Further, subsequent to December 31, 2015, the Company paid approximately $121 million under the terms of the Contractor Settlement Agreement. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs were reflected in the Company's previously disclosed in-service cost estimate. Further, as part of the settlement and in connection with the Acquisition: (i) Westinghouse has engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor; and (ii) the Vogtle Owners, CB&I, and The Shaw Group Inc. have entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On January 21, 2016, the Company submitted the Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement to the Georgia PSC for its review. On February 2, 2016, the Georgia PSC ordered the Company to file supplemental information by April 5, 2016 in support of the Contractor Settlement Agreement and the Company's position that all construction costs to date have been prudently incurred and that the current estimated in-service capital cost and schedule are reasonable. Following the Company's filing under the order, the Staff will conduct a review of all costs incurred related to Plant Vogtle Units 3 and 4, the schedule for completion of Plant Vogtle Units 3 and 4, and the Contractor Settlement Agreement and the Staff is authorized to engage in related settlement discussions with the Company and any intervenors.

The order provides that the Staff is required to report to the Georgia PSC by October 5, 2016 with respect to the status of its review and any settlement-related negotiations. If a settlement with the Staff is reached with respect to costs of Plant Vogtle Units 3 and 4, the Georgia PSC will then conduct a hearing to consider whether to approve that settlement. If a settlement with the Staff is not reached, the Georgia PSC will determine how to proceed, including (i) modifying the 2013 Stipulation, (ii) directing the Company to file a request for an amendment to the certificate for Plant Vogtle Units 3 and 4, (iii) issuing a scheduling order to address remaining disputed issues, or (iv) taking any other option within its authority.

The Georgia PSC has approved thirteen VCM reports covering the periods through June 30, 2015, including construction capital costs incurred, which through that date totaled $3.1 billion . On February 26, 2016, the Company filed its fourteenth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2015. The fourteenth VCM report does not include a requested amendment to the certified cost of Plant Vogtle Units 3 and 4. The Company is requesting approval of $160 million of construction capital costs incurred during that period. The Company anticipates to incur average financing costs of approximately $27 million per month from January 2016 until Plant Vogtle Units 3 and 4 are placed in service. The updated in-service capital cost forecast is $5.44 billion and includes costs related to the Contractor Settlement Agreement. Estimated financing costs during the construction period total approximately $2.4 billion . The Company's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.6 billion as of December 31, 2015.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance issues may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

As construction continues, the risk remains that challenges with Contractor performance including fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Future claims by the Contractor or the Company (on behalf of the Vogtle Owners) could arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement and, under the enhanced dispute resolution procedures, may be resolved through litigation after the completion of nuclear fuel load for both units.

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

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a ROE. The Company's share of purchased power totaled $78 million in 2015 , $84 million in 2014 , and $91 million in 2013 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company and Duke Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Duke Energy Florida, Inc. Subsequent to December 31, 2015, the Company exercised its contractual option to sell its ownership interest to Duke Energy Florida, Inc. contingent on regulatory approvals. The ultimate outcome of this matter cannot be determined at this time; however, no material impact on the Company's financial statements is expected.

At December 31, 2015 , the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	**Company Ownership**	**Plant in Service**	**Accumulated Depreciation**	**CWIP**
			(in millions)	
Plant Vogtle (nuclear)				
Units 1 and 2	45.7%	$ 3,503	$ 2,084	$ 63
Plant Hatch (nuclear)	50.1	1,230	568	90
Plant Wansley (coal)	53.5	915	290	13
Plant Scherer (coal)				
Units 1 and 2	8.4	260	86	1
Unit 3	75.0	1,223	433	1
Rocky Mountain (pumped storage)	25.4	181	125	—
Intercession City (combustion-turbine)	33.3	13	4	—

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

The Company also owns 45.7% of Plant Vogtle Units 3 and 4 that are currently under construction. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information.

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:

	2015	2014	2013
		(in millions)	
Federal –			
Current	**$ 515**	$ 295	$ 277
Deferred	**176**	366	374
	691	661	651
State –			
Current	**81**	82	(30)
Deferred	**(3)**	(14)	102
	78	68	72
Total	**$ 769**	$ 729	$ 723

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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:

	2015	2014
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	$ 4,909	$ 4,732
Property basis differences	943	811
Employee benefit obligations	310	329
Under-recovered fuel costs	—	81
Premium on reacquired debt	61	66
Regulatory assets associated with employee benefit obligations	528	534
Asset retirement obligations	706	497
Other	187	160
Total	7,644	7,210
Deferred tax assets –		
Federal effect of state deferred taxes	150	148
Employee benefit obligations	642	642
Other property basis differences	88	86
Other deferred costs	83	86
Cost of removal obligations	6	11
State investment tax credit carryforward	188	152
Federal tax credit carryforward	3	5
Over-recovered fuel costs	45	—
Unbilled fuel revenue	47	46
Asset retirement obligations	706	497
Other	59	63
Total	2,017	1,736
Accumulated deferred income taxes	$ 5,627	$ 5,474

On November 20, 2015, the FASB issued ASU 2015-17, which simplifies the presentation of deferred income taxes. The new guidance resulted in a reclassification from prepaid income taxes of $34 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. See Note 1 under "Recently Issued Accounting Standards" for additional information.

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation in 2015 and 2014.

At December 31, 2015 , tax-related regulatory assets to be recovered from customers were $683 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, 2015 , tax-related regulatory liabilities to be credited to customers were $105 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 average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $10 million in 2015 , $10 million in 2014 , and $5 million in 2013 . State investment tax and other tax credits are recognized in the period in which the credits are claimed on the state income tax return and totaled $33 million in 2015, $34 million in 2014, and $27 million in 2013. At December 31, 2015 , the Company had $3 million in federal tax credit carryforwards that will expire by 2035 and $188 million in state ITC carryforwards that will expire between 2020 and 2026.

Effective Tax Rate

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

	2015	2014	2013
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.5**	2.2	2.5
Non-deductible book depreciation	**1.2**	1.3	1.3
AFUDC equity	**(0.7)**	(0.8)	(0.6)
Other	**(0.4)**	(0.7)	(0.4)
Effective income tax rate	**37.6%**	37.0%	37.8%

The changes in the Company's effective tax rate are primarily the result of benefits related to emission allowances and state apportionment recorded in 2014.

Unrecognized Tax Benefits

Changes in unrecognized tax benefits were as follows:

	2015	2014	2013
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ —**	$ —	$ 23
Tax positions increase from prior periods	**3**	—	—
Tax positions decrease from prior periods	**—**	—	(23)
Balance at end of year	**$ 3**	$ —	$ —

The tax positions increase from prior periods for 2015 primarily relates to a graduated tax rate adjustment on the 2014 federal income tax return and will impact the Company's effective tax rate, if recognized. The tax positions decrease from prior periods for 2013 primarily relates to the Company's compliance with final U.S. Treasury regulations for a tax accounting method change for repairs.

These amounts are presented on a gross basis without considering the related federal or state income tax impact.

The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 and 2014 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.

6. FINANCING

Securities Due Within One Year

A summary of scheduled maturities of long-term debt due within one year at December 31 was as follows:

	2015	2014
	(in millions)	
Senior notes	**$ 700**	$ 1,050
Pollution control revenue bonds	**4**	98
Capital lease	**8**	6
Unamortized debt issuance expense	**—**	(4)
Total	**$ 712**	$ 1,150

Maturities through 2020 applicable to total long-term debt are as follows: $712 million in 2016 ; $459 million in 2017 ; $761 million in 2018 ; $512 million in 2019 ; and $49 million in 2020 .

Senior Notes

In December 2015, the Company issued $500 million aggregate principal amount of Series 2015A 1.95% Senior Notes due December 1, 2018. The proceeds were used to repay at maturity $250 million aggregate principal amount of the Company's Series Z 5.25% Senior Notes due December 15, 2015, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2015 and 2014 , the Company had $6.3 billion and $6.9 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $2.4 billion and $1.2 billion at December 31, 2015 and 2014 , respectively. As of December 31, 2015, the Company's secured debt included borrowings of $2.2 billion guaranteed by the DOE and capital lease obligations. As of December 31, 2014, the Company's secured debt was related to borrowings guaranteed by the DOE and capital lease obligations. See Note 7 for additional information.

See "DOE Loan Guarantee Borrowings" herein for additional information.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2015 and 2014 was $1.8 billion and $1.6 billion , respectively.

In May 2015, the Company reoffered to the public $104.6 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013, which had been previously purchased and held by the Company since 2013.

In August 2015, in connection with optional tenders, the Company repurchased and reoffered to the public $94.6 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2009 and $10 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013.

In November 2015, the Company reoffered to the public $89.2 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), Second Series 2009 and $46 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 1996, which had been previously repurchased and held by the Company since 2010.

Bank Term Loans

In March 2015, the Company entered into a $250 million aggregate principal amount three -month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes and the loan was repaid at maturity.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) in February 2014, under which the DOE agreed to guarantee the obligations of the Company under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, the Company, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which the Company may make term loan borrowings through the FFB.

Proceeds of advances made under the FFB Credit Facility are used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion .

All borrowings under the FFB Credit Facility are full recourse to the Company, and the Company is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. The Company's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant

Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on the Company's ability to grant liens on other property.

Advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375% .

In February 2014, the Company made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion . The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029, and is expected to be reset from time to time thereafter through 2044. In connection with its entry into the agreements with the DOE and the FFB, the Company incurred issuance costs of approximately $66 million , which are being amortized over the life of the borrowings under the FFB Credit Facility.

In December 2014, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million . The interest rate applicable to the $200 million advance in December 2014 under the FFB Credit Facility is 3.002% for an interest period that extends to 2044.

In June and December 2015, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $600 million and $400 million , respectively. The interest rate applicable to the $600 million principal amount is 3.283% and the interest rate applicable to the $400 million principal amount is 3.072% , both for an interest period that extends to 2044.

Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Under the Loan Guarantee Agreement, the Company is subject to customary borrower affirmative and negative covenants and events of default. In addition, the Company is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and the Company will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. The Company also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Promissory Note, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume the Company's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of the Company's ownership interest in Plant Vogtle Units 3 and 4.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2015 and 2014, the Company had a capital lease asset for its corporate headquarters building of $61 million , with accumulated depreciation at December 31, 2015 and 2014 of $26 million and $21 million , respectively. At December 31, 2015 and 2014 , the capitalized lease obligation was $35 million and $40 million , respectively, with an annual interest rate of 7.9% for both years. For ratemaking purposes, the Georgia PSC has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. The annual expense incurred for all capital leases was not material for any year presented.

At December 31, 2015, the Company had capital lease assets and corresponding obligations of $149 million and $148 million , respectively, for two affiliate PPAs that became effective in 2015. Contractual lease payments, including imputed interest, of $20 million and capital lease asset amortization of $10 million were included in purchased power, affiliates expense in 2015. The annual imputed interest rates will range from 13% to 14% for these two capital lease PPAs over their term. For ratemaking purposes, the Georgia PSC has allowed the capital lease asset amortization in cost of service and the imputed interest in the Company's cost of debt. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Assets Subject to Lien

See "DOE Loan Guarantee Borrowings" above for information regarding certain borrowings of the Company that are secured by a first priority lien on (i) the Company’s 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4.

See "Capital Leases" above for information regarding certain assets held under capital leases.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. The outstanding series of the Class A preferred stock is subject to redemption at the option of the Company at any time at a redemption price equal to 100% of the par value. In addition, on or after October 1, 2017, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the par value. With respect to any redemption of the preference stock prior to October 1, 2017, the redemption price includes a make-whole premium based on the present value of the liquidation amount and future dividends through the first par redemption date.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2015, the Company had a $1.75 billion committed credit arrangement with banks, of which $1.73 billion was unused. These credit arrangements expire in 2020.

In August 2015, the Company amended and restated its multi-year credit arrangement, which, among other things, extended the maturity date from 2018 to 2020. The Company increased its borrowing ability by $150 million under its facility maturing in 2020 and terminated its aggregate $150 million facilities maturing in 2016.

Subject to applicable market conditions, the Company expects to renew this bank credit arrangement, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitments thereunder. This bank credit arrangement requires payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than $^1/_4$ of 1% for the Company.

The bank credit arrangement contains a covenant that limits the Company's debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes certain hybrid securities.

A portion of the $1.73 billion unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and its commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2015 was $872 million . In addition, at December 31, 2015, the Company had $69 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

Details of short-term borrowings outstanding were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2015:		
Commercial paper	**$ 158**	**0.6%**
December 31, 2014:		
Commercial paper	$ 156	0.3%

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 and nuclear fuel which are not recognized on the balance sheets. In 2015, 2014, and 2013, the Company incurred fuel expense of $2.0 billion , $2.5 billion , and $2.3 billion , 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. On December 15, 2015, the Company's natural gas hedging program was revised and approved by the Georgia PSC.

The Company has commitments regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of MEAG Power's Plant Vogtle Units 1 and 2 allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $10 million , $19 million , and $27 million in 2015, 2014, and 2013, respectively.

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The Company has also entered into various long-term PPAs, some of which are accounted for as capital or operating leases. Total capacity expense under PPAs accounted for as operating leases was $203 million , $167 million , and $162 million for 2015, 2014, and 2013, respectively. Estimated total long-term obligations at December 31, 2015 were as follows:

	Affiliate Capital Leases	Affiliate Operating Leases	Non-Affiliate Operating Leases (4)	Vogtle Units 1 and 2 Capacity Payments	Total ($)
			(in millions)		
2016	$ 22	$ 99	$ 115	$ 10	$ 246
2017	22	71	123	8	224
2018	22	62	126	7	217
2019	23	63	127	8	221
2020	23	64	123	4	214
2021 and thereafter	227	538	1,007	47	1,819
Total	$ 339	$ 897	$ 1,621	$ 84	$ 2,941
Less: amounts representing executory costs (1)	54				
Net minimum lease payments	285				
Less: amounts representing interest (2)	84				
Present value of net minimum lease payments (3)	$ 201				

(1) Executory costs such as taxes, maintenance, and insurance (including the estimated profit thereon) a re estimated and included in total minimum lease payments.

(2) Amount necessary to reduce minimum lease payments to present value calculated at the Company's incremental borrowing rate at the inception of the leases.

(3) Once service commenced under the PPAs beginning in 2015, the Company recognized capital lease assets and capital lease obligations totaling $149 million , being the lesser of the estimated fair value of the lease property or the present value of the net minimum lease payments.

(4) A total of $304 million of biomass PPAs included under the non-affiliate operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action.

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 operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the PPA operating leases discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $29 million for 2015 , $28 million for 2014 , and $32 million for 2013 . The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2015, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
		(in millions)	
2016	$ 15	$ 8	$ 23
2017	10	8	18
2018	5	7	12
2019	1	7	8
2020	1	6	7
2021 and thereafter	3	13	16
Total	$ 35	$ 49	$ 84

Railcar minimum lease payments are disclosed at 100% of railcar lease obligations; however, a portion of these obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the railcar leases are recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

In addition to the above rental commitments, the Company has obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $32 million . At the termination of the leases, the lessee may either renew the lease, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

Alabama Power has guaranteed the obligations of SEGCO for $25 million of pollution control revenue bonds issued in 2001, which mature in June 2019 and also $100 million of senior notes issued in November 2013, which mature in December 2018. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of SEGCO's stock if Alabama Power is called upon to make such payment under its guarantee. See Note 4 for additional information.

In addition, in 2013, the Company entered into an agreement that requires the Company to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years . The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2017. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million .

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to railcar leases.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation, in the form of Southern Company stock options and 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, 2015 , there were 1,002 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. As a result, stock-based compensation granted to employees in 2015 consisted exclusively of performance share units.

For the years ended December 31, 2014 and 2013, employees of the Company were granted stock options for 2,034,150 shares and 1,509,662 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014 and 2013 derived using the Black-Scholes stock option pricing model was $2.20 and $2.93 , respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented. As of December 31, 2015 , 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, 2015 , 2014 , and 2013 was $9 million , $19 million , and $16 million , respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $4 million , $7 million , and $6 million for the years ended December 31, 2015 , 2014 , and 2013 , respectively. As of December 31, 2015 , the aggregate intrinsic value for the options outstanding and options exercisable was $45 million and $38 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 which equates to the requisite service period for accounting purposes. 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, issued in 2015, 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, 2015, 2014, and 2013, employees of the Company were granted performance share units of 236,804 , 176,224 , and 161,240 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2015, 2014, and 2013, 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 $46.41 , $37.54 , and $40.50 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2015 was $47.78 .

For the years ended December 31, 2015 , 2014 , and 2013 , total compensation cost for performance share units recognized in income was $15 million , $6 million , and $6 million , respectively, with the related tax benefit also recognized in income of $6 million , $2 million , and $2 million , respectively. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2015 , there was $4 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 19 months .

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $13.5 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests in all licensed reactors, is $247 million , per incident, but not more than an aggregate of $37 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years . The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. In April 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks , with a maximum per occurrence per unit limit of $490 million . After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years . The Company purchases limits based on the projected full cost of replacement power, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The current maximum annual assessments for the Company under the NEIL policies would be $84 million .

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12 -month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

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

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

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

As of December 31, 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:				
Energy-related derivatives	$ —	$ 2	$ —	$ 2
Interest rate derivatives	—	5	—	5
Nuclear decommissioning trusts:(*)				
Domestic equity	182	1	—	183
Foreign equity	—	113	—	113
U.S. Treasury and government agency securities	—	125	—	125
Municipal bonds	—	64	—	64
Corporate bonds	—	143	—	143
Mortgage and asset backed securities	—	127	—	127
Other	16	4	—	20
Cash equivalents	63	—	—	63
Total	$ 261	$ 584	$ —	$ 845
Liabilities:				
Energy-related derivatives	$ —	$ 15	$ —	$ 15
Interest rate derivatives	—	6	—	6
Total	$ —	$ 21	$ —	$ 21

(*) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2014 , 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, 2014:	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	$ —	$ 7	$ —	$ 7
Interest rate derivatives	—	6	—	6
Nuclear decommissioning trusts:(*)				
Domestic equity	180	2	—	182
Foreign equity	—	121	—	121
U.S. Treasury and government agency securities	—	96	—	96
Municipal bonds	—	62	—	62
Corporate bonds	—	188	—	188
Mortgage and asset backed securities	—	121	—	121
Other	11	8	—	19
Total	$ 191	$ 611	$ —	$ 802
Liabilities:				
Energy-related derivatives	$ —	$ 27	$ —	$ 27
Interest rate derivatives	—	14	—	14
Total	$ —	$ 41	$ —	$ 41

(*) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflect the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available. See Note 1 under "Nuclear Decommissioning" for additional information.

The Company early adopted ASU 2015-07 effective December 31, 2015 on a retrospective basis. The guidance removed certain disclosures required for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. As of December 31, 2015 and 2014, the Company had no investments measured at net asset value as a practical expedient.

As of December 31, 2015 and 2014 , 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, including securities due within one year:		
2015	**$ 10,145**	**$ 10,480**
2014	$ 9,673	$ 10,552

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

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 10 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 commodity fuel prices and prices of electricity. The Company manages a fuel-hedging program, implemented per the guidelines of the Georgia 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 two methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging program, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery mechanism.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2015 , the net volume of energy-related derivative contracts for natural gas positions totaled 50 million mmBtu, all of which expire by 2017 , which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 4 million mmBtu for the Company.

Interest Rate Derivatives

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

At December 31, 2015 , 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, 2015
	(in millions)				*(in millions)*
Cash Flow Hedges of Existing Debt					
	$ 250	3-month LIBOR + 0.32%	0.75%	March 2016	$ —
	200	3-month LIBOR + 0.40%	1.01%	August 2016	—
Fair Value Hedges of Existing Debt					
	250	5.40%	3-month LIBOR + 4.02%	June 2018	1
	200	4.25%	3-month LIBOR + 2.46%	December 2019	2
	500	1.95%	3-month LIBOR + .76%	December 2018	(3)
Total	$ 1,400				$ —

The estimated pre-tax gains (losses) that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2016 are $4 million . The Company has deferred gains and losses related to interest rate derivative settlements of cash flow hedges that are expected to be amortized into earnings through 2037 .

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Derivative Financial Statement Presentation and Amounts

At December 31, 2015 and 2014 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 2**	$ 6	Liabilities from risk management activities	**$ 12**	$ 23
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**3**	4
Total derivatives designated as hedging instruments for regulatory purposes		**$ 2**	$ 7		**$ 15**	$ 27
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	**$ 5**	$ 5	Liabilities from risk management activities	**$ —**	$ 9
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**6**	5
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 5**	$ 6		**$ 6**	$ 14
Total		**$ 7**	$ 13		**$ 21**	$ 41

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2015 and 2014 .

The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts 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. Amounts related to energy-related derivative contracts and interest rate derivative contracts at December 31, 2015 and 2014 are presented in the following tables.

	Fair Value				
Assets	**2015**	2014	**Liabilities**	**2015**	2014
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 2**	$ 7	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 15**	$ 27
Gross amounts not offset in the Balance Sheet [(b)]	**(2)**	(7)	Gross amounts not offset in the Balance Sheet [(b)]	**(2)**	(7)
Net energy-related derivative assets	**$ —**	$ —	**Net energy-related derivative liabilities**	**$ 13**	$ 20
Interest rate derivatives presented in the Balance Sheet [(a)]	**$ 5**	$ 6	Interest rate derivatives presented in the Balance Sheet [(a)]	**$ 6**	$ 14
Gross amounts not offset in the Balance Sheet [(b)]	**(4)**	(6)	Gross amounts not offset in the Balance Sheet [(b)]	**(4)**	(6)
Net interest rate derivative assets	**$ 1**	$ —	**Net interest rate derivative liabilities**	**$ 2**	$ 8

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

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At December 31, 2015 and 2014 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (12)**	$ (23)	Other regulatory liabilities, current	**$ 2**	$ 6
	Other regulatory assets, deferred	**(3)**	(4)	Other deferred credits and liabilities	**—**	1
Total energy-related derivative gains (losses)		**$ (15)**	$ (27)		**$ 2**	$ 7

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2015**	2014	2013	**Statements of Income Location**	**2015**	2014	2013
	(in millions)				*(in millions)*		
Interest rate derivatives	**$ (15)**	$ (8)	$ —	Interest expense, net of amounts capitalized	**$ (3)**	$ (3)	$ (3)

For the years ended December 31, 2015 and 2014 , the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on the statements of income were immaterial on a gross basis for the Company. Furthermore, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the Company's statements of income were offset by changes to the carrying value of long-term debt. The gains and losses related to interest rate derivative settlements of fair value hedges are recorded directly to earnings.

There was no material ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was immaterial for all years 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, 2015 , the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2015 , the fair value of derivative liabilities with contingent features was $1 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $52 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

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12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2015 and 2014 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2015	**$ 1,978**	**$ 454**	**$ 236**
June 2015	**2,016**	**554**	**277**
September 2015	**2,691**	**964**	**551**
December 2015	**1,641**	**376**	**196**
March 2014	$ 2,269	$ 516	$ 266
June 2014	2,186	572	311
September 2014	2,631	920	525
December 2014	1,902	288	123

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

SELECTED FINANCIAL AND OPERATING DATA 2011 - 2015
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	2015	2014	2013	2012	2011
Operating Revenues (in millions)	**$ 8,326**	$ 8,988	$ 8,274	$ 7,998	$ 8,800
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 1,260**	$ 1,225	$ 1,174	$ 1,168	$ 1,145
Cash Dividends on Common Stock (in millions)	**$ 1,034**	$ 954	$ 907	$ 983	$ 1,096
Return on Average Common Equity (percent)	**11.92**	12.24	12.45	12.76	12.89
Total Assets (in millions) [a][b]	**$ 32,865**	$ 30,872	$ 28,776	$ 28,618	$ 27,045
Gross Property Additions (in millions)	**$ 2,332**	$ 2,146	$ 1,906	$ 1,838	$ 1,981
Capitalization (in millions):					
Common stock equity	**$ 10,719**	$ 10,421	$ 9,591	$ 9,273	$ 9,023
Preferred and preference stock	**266**	266	266	266	266
Long-term debt [a]	**9,616**	8,563	8,571	7,928	7,944
Total (excluding amounts due within one year)	**$ 20,601**	$ 19,250	$ 18,428	$ 17,467	$ 17,233
Capitalization Ratios (percent):					
Common stock equity	**52.0**	54.1	52.0	53.1	52.4
Preferred and preference stock	**1.3**	1.4	1.4	1.5	1.5
Long-term debt [a]	**46.7**	44.5	46.6	45.4	46.1
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**2,127,658**	2,102,673	2,080,358	2,062,040	2,047,390
Commercial [c]	**304,179**	301,246	298,420	296,397	295,288
Industrial [c]	**9,141**	9,132	9,136	9,143	9,134
Other	**9,261**	9,003	8,623	7,724	7,521
Total	**2,450,239**	2,422,054	2,396,537	2,375,304	2,359,333
Employees (year-end)	**7,989**	7,909	7,886	8,094	8,310

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $124 million, $62 million, $67 million, and $75 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-03. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(b) A reclassification of deferred tax assets from Total Assets of $34 million, $68 million, $117 million, and $31 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-17. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(c) A reclassification of customers from commercial to industrial is reflected for years 2011-2013 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

SELECTED FINANCIAL AND OPERATING DATA 2011 - 2015 (continued)
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	2015	2014	2013	2012	2011
Operating Revenues (in millions):					
Residential	$ 3,240	$ 3,350	$ 3,058	$ 2,986	$ 3,241
Commercial	3,094	3,271	3,077	2,965	3,217
Industrial	1,305	1,525	1,391	1,322	1,547
Other	88	94	94	89	94
Total retail	7,727	8,240	7,620	7,362	8,099
Wholesale — non-affiliates	215	335	281	281	341
Wholesale — affiliates	20	42	20	20	32
Total revenues from sales of electricity	7,962	8,617	7,921	7,663	8,472
Other revenues	364	371	353	335	328
Total	$ 8,326	$ 8,988	$ 8,274	$ 7,998	$ 8,800
Kilowatt-Hour Sales (in millions):					
Residential	26,649	27,132	25,479	25,742	27,223
Commercial	32,719	32,426	31,984	32,270	32,900
Industrial	23,805	23,549	23,087	23,089	23,519
Other	632	633	630	641	657
Total retail	83,805	83,740	81,180	81,742	84,299
Wholesale — non-affiliates	3,501	4,323	3,029	2,934	3,904
Wholesale — affiliates	552	1,117	496	600	626
Total	87,858	89,180	84,705	85,276	88,829
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.16	12.35	12.00	11.60	11.91
Commercial	9.46	10.09	9.62	9.19	9.78
Industrial	5.48	6.48	6.03	5.73	6.58
Total retail	9.22	9.84	9.39	9.01	9.61
Wholesale	5.80	6.93	8.54	8.52	8.23
Total sales	9.06	9.66	9.35	8.99	9.54
Residential Average Annual Kilowatt-Hour Use Per Customer	12,582	12,969	12,293	12,509	13,288
Residential Average Annual Revenue Per Customer	$ 1,529	$ 1,605	$ 1,475	$ 1,451	$ 1,582
Plant Nameplate Capacity Ratings (year-end) (megawatts)	15,455	17,593	17,586	17,984	16,588
Maximum Peak-Hour Demand (megawatts):					
Winter	15,735	16,308	12,767	14,104	14,800
Summer	16,104	15,777	15,228	16,440	16,941
Annual Load Factor (percent)	61.9	61.2	63.5	59.1	59.5
Plant Availability (percent) * :					
Fossil-steam	85.6	86.3	87.1	90.3	88.6
Nuclear	94.1	90.8	91.8	94.1	92.2
Source of Energy Supply (percent):					
Coal	24.5	30.9	26.4	26.6	44.4
Nuclear	17.6	16.7	17.7	18.3	16.6
Hydro	1.6	1.3	2.0	0.7	1.1
Oil and gas	28.3	26.3	29.6	22.0	8.9
Purchased power —					
From non-affiliates	5.0	3.8	3.3	6.8	6.1
From affiliates	23.0	21.0	21.0	25.6	22.9
Total	100.0	100.0	100.0	100.0	100.0

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

GULF POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2015 Annual Report

The management of Gulf Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (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, 2015 .

/s/ S. W. Connally, Jr.
S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer

/s/ Xia Liu
Xia Liu
Vice President and Chief Financial Officer

February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2015 and 2014 , and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2015 . 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 II-319 to II-357) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2015 and 2014 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015 , in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 26, 2016

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power, Gulf Power Company, and Mississippi Power

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Gulf Power Company 2015 Annual Report

OVERVIEW

Business Activities

Gulf Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, restoration following major storms, and fuel. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. Through 2015, capacity revenues represented the majority of the Company's wholesale earnings. The Company had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 (205 MWs) and these capacity revenues represented 82% of total wholesale capacity revenues for 2015. Due to the expiration of a wholesale contract at the end of 2015 and future expiration dates of the remaining wholesale contracts for the unit, the Company currently has contracts to cover 34% of the unit for 2016 and 27% of the unit through 2019. Although the Company is actively evaluating alternatives relating to this asset, including replacement wholesale contracts, the expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts will have a material negative impact on the Company's earnings in 2016 and may continue to have a material negative impact in future years. In the event some portion of the Company's ownership of Plant Scherer Unit 3 is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the Southern Company power pool or into the wholesale market.

In 2013, the Florida PSC voted to approve the settlement agreement (2013 Rate Case Settlement Agreement) among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million annually effective January 2014 and subsequently increased base rates approximately $20 million annually effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); (3) may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017, of which $28.5 million had been recorded as of December 31, 2015; and (4) is accruing a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Retail Base Rate Case" herein for additional details of the 2013 Rate Case Settlement Agreement.

Key Performance Indicators

The Company continues to focus on several key performance indicators including customer satisfaction, plant availability, system reliability, and net income after dividends on preference 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 of these surveys in measuring performance, which the Company achieved in 2015.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's 2015 Peak Season EFOR of 0.87% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's performance for 2015 was better than the target for these transmission and distribution reliability measures.

The Company uses net income after dividends on preference stock as the primary measure of the Company's financial performance. See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Earnings

The Company's 2015 net income after dividends on preference stock was $148 million , representing an $8 million, or 5.7%, increase over the previous year. The increase was primarily due to an increase in retail base revenues effective January 1, 2015, and a reduction in depreciation, both as authorized in the 2013 Rate Case Settlement Agreement, partially offset by higher operations and maintenance expenses as compared to the corresponding period in 2014.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2015 Annual Report

In 2014, the net income after dividends on preference stock was $140 million, representing a $16 million, or 12.7%, increase over the previous year. The increase was primarily due to higher retail revenues, partially offset by higher other operations and maintenance expenses as compared to the corresponding period in 2013.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2015	**2015**	2014
		(in millions)	
Operating revenues	**$ 1,483**	**$ (107)**	$ 150
Fuel	**445**	**(160)**	72
Purchased power	**135**	**28**	22
Other operations and maintenance	**354**	**13**	31
Depreciation and amortization	**141**	**(4)**	(4)
Taxes other than income taxes	**118**	**7**	13
Total operating expenses	**1,193**	**(116)**	134
Operating income	**290**	**9**	16
Total other income and (expense)	**(41)**	**3**	9
Income taxes	**92**	**4**	8
Net income	**157**	**8**	17
Dividends on preference stock	**9**	**—**	1
Net income after dividends on preference stock	**$ 148**	**$ 8**	$ 16

Operating Revenues

Operating revenues for 2015 were $1.48 billion , reflecting a decrease of $107 million from 2014. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2015	2014
	(in millions)	
Retail — prior year	**$ 1,267**	$ 1,170
Estimated change resulting from –		
Rates and pricing	**22**	47
Sales growth	**—**	8
Weather	**3**	10
Fuel and other cost recovery	**(43)**	32
Retail — current year	**1,249**	1,267
Wholesale revenues –		
Non-affiliates	**107**	129
Affiliates	**58**	130
Total wholesale revenues	**165**	259
Other operating revenues	**69**	64
Total operating revenues	**$ 1,483**	$ 1,590
Percent change	**(6.7)%**	10.4%

In 2015, retail revenues decreased $18 million, or 1.4%, when compared to 2014 primarily as a result of lower fuel cost recovery revenues partially offset by higher revenues associated with purchased power capacity costs and higher revenues resulting from an increase in retail base rates, as authorized in the 2013 Rate Case Settlement Agreement, as well as an increase in the environmental and energy conservation cost recovery clause rates, both effective in January 2015. In 2014, retail revenues increased $97 million, or 8.3%, when compared to 2013 primarily as a result of higher fuel cost recovery revenues and higher revenues resulting from an increase in retail base rates effective January 2014, as authorized in the 2013 Rate Case Settlement Agreement. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

In 2015, revenues associated with changes in rates and pricing included higher revenues due to increases in retail base rates and the Company's environmental and energy conservation cost recovery clauses. In 2014, revenues associated with changes in rates and pricing included higher revenues due to an increase in retail base rates and revenues associated with higher rates under the Company's environmental cost recovery clause. Annually, the Company petitions the Florida PSC for recovery of projected environmental and energy conservation costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate case and cost recovery clauses, including the Company's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

Wholesale revenues from power sales to non-affiliated utilities were as follows:

	2015	2014	2013
		(in millions)	
Capacity and other	**$ 67**	$ 65	$ 64
Energy	**40**	64	45
Total non-affiliated	**$ 107**	$ 129	$ 109

Wholesale revenues from sales to non-affiliates consist of long-term sales agreements to other utilities in Florida and Georgia and short-term opportunity sales. Capacity revenues from long-term sales agreements represent the greatest contribution to net income. The energy is generally sold at variable cost. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy. Wholesale energy revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. See FUTURE EARNINGS POTENTIAL – "General" for additional information regarding the expiration of long-term sales agreements for Plant Scherer Unit 3, which will materially impact future wholesale earnings.

In 2015, wholesale revenues from sales to non-affiliates decreased $22 million, or 17.1%, as compared to the prior year primarily due to a 37.7% decrease in KWH sales resulting from lower sales under the Plant Scherer Unit 3 long-term sales agreements due to a planned outage and lower natural gas market prices that led to increased self-generation from customer-owned units. In 2014, wholesale revenues from sales to non-affiliates increased $20 million, or 18.1%, as compared to the prior year primarily due to a 43.7% increase in KWH sales as a result of lower-priced energy supply alternatives from the Southern Company system's resources and fewer planned outages at Plant Scherer Unit 3 partially offset by a 1.9% decrease in the price of energy sold to non-affiliates due to the lower cost of fuel per KWH generated.

Wholesale revenues from sales to affiliated companies 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 the revenue related to these energy sales generally offsets the cost of energy sold. In 2015, wholesale revenues from sales to affiliates decreased $72 million, or 55.4%, as compared to the prior year primarily due to a 23.5% decrease in the price of energy sold to affiliates due to lower power pool interchange rates resulting from lower natural gas market prices and a 42.0% decrease in KWH sales that resulted from the availability of lower-cost generation alternatives. In 2014, wholesale revenues from sales to affiliates increased $30 million, or 30.7%, as compared to the prior year primarily due to a 24.5% increase in the price of energy sold to affiliates due to higher marginal generation costs and a 5.0% increase in KWH sales as a result of an increase of the Company's generation dispatched to serve affiliated companies' higher weather-related energy demand primarily in the first and third quarters of 2014.

Other operating revenues increased $5 million, or 7.8%, in 2015 as compared to the prior year primarily due to a $2 million increase in franchise fees and a $2 million increase in revenues from other energy services. In 2014, other operating revenues increased $3 million, or 5.5%, as compared to the prior year primarily due to a $5 million increase in franchise fees due to increased retail revenues, partially offset by a $2 million decrease in revenues from other energy services. Franchise fees have no impact on net income. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2015 and the percent change from the prior year were as follows:

	Total KWHs	**Total KWH Percent Change**		**Weather-Adjusted Percent Change**	
	2015	**2015**	2014	**2015**	2014
	(in millions)				
Residential	**5,365**	**— %**	5.4%	**(1.0)%**	1.3%
Commercial	**3,898**	**1.6**	0.7	**0.3**	0.1
Industrial	**1,798**	**(2.8)**	8.8	**(2.8)**	8.8
Other	**25**	**(0.1)**	20.5	**(0.1)**	20.5
Total retail	**11,086**	**0.1**	4.3	**(0.8)%**	2.1%
Wholesale					
Non-affiliates	**1,040**	**(37.7)**	43.7		
Affiliates	**1,906**	**(42.0)**	5.0		
Total wholesale	**2,946**	**(40.5)**	15.5		
Total energy sales	**14,032**	**(12.5)%**	7.5%		

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.

Residential KWH sales increased minimally in 2015 compared to 2014 due to customer growth and warmer weather in the second and third quarters of 2015, mostly offset by a decline in use per customer. Residential KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth.

Commercial KWH sales increased in 2015 compared to 2014 due to customer growth and warmer weather in the second and third quarters of 2015, partially offset by a decline in use per customer. Commercial KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth, partially offset by a decline in weather-adjusted use per customer.

Industrial KWH sales decreased in 2015 compared to 2014 primarily due to increased customer co-generation as a result of lower natural gas prices, partially offset by increases due to changes in customers' operations. Industrial KWH sales increased in 2014 compared to 2013 primarily due to decreased customer co-generation and changes in customers' operations.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2015 Annual Report

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

	2015	2014	2013
Total generation *(millions of KWHs)*	**8,629**	11,109	9,216
Total purchased power *(millions of KWHs)*	**5,976**	5,547	6,298
Sources of generation *(percent)* –			
Coal	**57**	67	61
Gas	**43**	33	39
Cost of fuel, generated *(cents per net KWH)* –			
Coal [(a)]	**3.88**	4.03	4.12
Gas	**4.22**	3.93	3.95
Average cost of fuel, generated *(cents per net KWH)* [(a)]	**4.03**	3.99	4.05
Average cost of purchased power *(cents per net KWH)* [(b)]	**3.89**	4.83	3.88

(a) 2013 cost of coal includes the effect of a payment received pursuant to the resolution of a coal contract dispute.
(b) Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

In 2015, total fuel and purchased power expenses were $580 million, a decrease of $132 million, or 18.5%, from the prior year costs. The decrease was primarily the result of a $79 million decrease due to a lower volume of KWHs generated and purchased due to the availability of lower-cost generation alternatives and a $53 million decrease due to a lower average cost of fuel and purchased power.

In 2014, total fuel and purchased power expenses were $712 million, an increase of $94 million, or 15.2%, from the prior year costs. Total fuel and purchased power expenses for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the higher volume of KWHs generated and purchased increased expenses $55 million primarily due to increased Company owned generation dispatched to serve higher Southern Company system demand as a result of colder weather in the first quarter and warmer weather in the third quarter 2014. The increased expenses also included an $18 million increase due to a higher average cost of fuel and purchased power.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel and purchased power capacity cost recovery clauses and long-term wholesale contracts. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" and " – Purchased Power Capacity Recovery" for additional information.

Fuel

Fuel expense was $445 million in 2015, a decrease of $160 million, or 26.4%, from the prior year costs. The decrease was primarily due to a 22.3% lower volume of KWHs generated due to the availability of lower-cost generation alternatives, partially offset by a 1.0% increase in the average cost of fuel due to higher natural gas prices per KWH generated. In 2014, fuel expense was $605 million , an increase of $72 million, or 13.5%, from the prior year costs. The increase was primarily due to a 20.5% higher volume of KWHs generated to serve higher Southern Company system loads due to colder weather in the first quarter 2014 and warmer weather in the third quarter 2014. The fuel expense for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel per KWH generated decreased 6.8%.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $100 million in 2015, an increase of $18 million, or 22.0%, from the prior year. The increase was primarily due to a $26 million increase in capacity costs associated with a scheduled price increase for an existing PPA, partially offset by the expiration of another PPA, an 11.9% decrease in the average cost per KWH purchased due to lower market prices for fuel, and a 7.8% decrease in the volume of KWHs purchased due to the availability of lower-cost generation alternatives. In 2014, purchased power expense from non-affiliates was $82 million in 2014, an increase of $30 million, or 56.3%, from the prior year. The increase was due to a 37.3% increase in the average cost per KWH purchased, which included a $28 million increase in capacity costs associated with a scheduled price increase for an existing PPA, partially offset by the expiration of another PPA. This increase was partially offset by a 16.3% decrease in the volume of KWHs purchased due to colder regional weather conditions in the first quarter 2014 which limited the availability of market resources.

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

Purchased Power – Affiliates

Purchased power expense from affiliates was $35 million in 2015, an increase of $10 million, or 40.0%, from the prior year. The increase was primarily due to a 108.9% increase in the volume of KWHs purchased primarily due to the availability of lower-cost generation alternatives available from the power pool, partially offset by a 34.2% decrease in the average cost per KWH purchased due to lower power pool interchange rates. In 2014, purchased power expense from affiliates was $25 million , a decrease of $8 million, or 23.1%, from the prior year. The decrease was primarily due to a 43.3% decrease in the average cost per KWH purchased, which included a $14 million reduction in capacity costs primarily associated with the expiration of an existing PPA. This decrease was partially offset by a 33.2% increase in the volume of KWHs purchased primarily due to higher planned outages for the Company's generating units in the fourth quarter 2014.

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

Other Operations and Maintenance Expenses

In 2015, other operations and maintenance expenses increased $13 million, or 3.8%, compared to the prior year primarily due to increases of $6 million in employee compensation and benefits including pension costs, amortization of $3 million of expenses previously incurred in retail base rate cases as authorized in the 2013 Rate Case Settlement Agreement, and $2 million in energy service contracts. In 2014, other operations and maintenance expenses increased $31 million, or 10.1%, compared to the prior year primarily due to increases in routine and planned maintenance expenses at generation, transmission and distribution facilities.

Expenses from energy services did not have a significant impact on earnings since they were generally offset by associated revenues.

Depreciation and Amortization

Depreciation and amortization decreased $4 million, or 2.8%, in 2015 compared to the prior year. As authorized in the 2013 Rate Case Settlement Agreement, the Company recorded an $11.7 million additional reduction in depreciation in 2015 as compared to 2014. This decrease was partially offset by an increase of $8 million primarily attributable to property additions at transmission and distribution facilities. In 2014, depreciation and amortization decreased $4 million, or 2.7%, compared to the prior year. As authorized in the 2013 Rate Case Settlement Agreement, the Company recorded an $8.4 million reduction in depreciation in 2014. This decrease was partially offset by increases of $4 million primarily attributable to property additions at generation, transmission, and distribution facilities. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $7 million, or 6.3%, in 2015 compared to the prior year primarily due to increases of $3 million in property taxes, $2 million in franchise fees and $2 million in gross receipts taxes. In 2014, taxes other than income taxes increased $13 million, or 13.0%, compared to the prior year primarily due to increases of $4 million in franchise fees and $4 million in gross receipts taxes as well as a $3 million increase in property taxes. Gross receipts taxes and franchise fees are based on billed revenues and have no impact on net income. These taxes are collected from customers and remitted to governmental agencies.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $4 million, or 7.5%, in 2015 compared to the prior year primarily due to $6 million in deferred returns on transmission projects, which reduce interest expense and are recorded as a regulatory asset, as authorized in the 2013 Rate Case Settlement Agreement. This decrease was partially offset by a $2 million increase in interest expense related to long-term debt resulting from the issuance of senior notes in 2014. In 2014, interest expense, net of amounts capitalized decreased $3 million, or 5.0%, compared to the prior year primarily due to an increase in capitalization of AFUDC debt related to the construction of environmental control projects and lower interest rates on pollution control bonds, offset by increases in long-term debt resulting from the issuance of additional senior notes in 2014.

Income Taxes

Income taxes increased $4 million, or 4.5%, in 2015 compared to the prior year primarily due to higher pre-tax earnings. In 2014, income taxes increased $8 million, or 10.5%, compared to the prior year primarily due to higher pre-tax earnings. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, the rate of economic growth or decline in the Company's service territory, and the successful remarketing of wholesale capacity as current contracts expire. Demand for electricity is partially 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.

The Company's wholesale business consists of two types of agreements. The first type, referred to as requirements service, provides that the Company serves the customer's capacity and energy requirements from Company resources. The second type, referred to as a unit sale, is a wholesale customer purchase from a dedicated generating plant unit where a portion of that unit is reserved for the customer. These agreements are associated with the Company's ownership of Plant Scherer Unit 3 and consist of both capacity and energy sales. Through 2015, capacity revenues represented the majority of the Company's wholesale earnings. The Company had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 and these capacity revenues represented 82% of total wholesale capacity revenues for 2015. Due to the expiration of a wholesale contract at the end of 2015 and future expiration dates of the remaining wholesale contracts for the unit, the Company currently has contracts to cover 34% of the unit for 2016 and 27% of the unit through 2019. Although the Company is actively evaluating alternatives relating to this asset, including replacement wholesale contracts, the expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts will have a material negative impact on the Company's earnings in 2016 and may continue to have a material negative impact in future years. In the event some portion of the Company's ownership of Plant Scherer Unit 3 is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the Southern Company power pool or into the wholesale market.

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 retail rates or through long-term wholesale agreements on a timely basis or through market-based contracts. The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The Company's current long-term wholesale agreements contain provisions that permit charging the customer with costs incurred as a result of changes in environmental laws and regulations. The full impact of any such regulatory or legislative changes cannot be determined at this time. 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 or long-term wholesale agreements could contribute to reduced demand for electricity as well as impact the cost competitiveness of wholesale capacity, which could negatively affect results of operations, cash flows, and financial condition. See "Other Matters" herein and Note 3 to the financial statements under "Environmental Matters" and "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" for additional information, including a discussion on the State of Florida's statutory provisions on environmental cost recovery.

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 2015 , the Company had invested approximately $1.9 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $116 million, $227 million, and $143 million for 2015 , 2014 , and 2013 , respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $117 million from 2016 through 2018 , with annual totals of approximately $30 million, $43 million, and $44 million for 2016 , 2017 , and 2018 , respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information. The Company also anticipates costs associated with closure in place and ground water monitoring of ash ponds in accordance with the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation (ARO) liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, 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.

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. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. The compliance deadline set by the final MATS rule was April 16, 2015, with provisions for extensions to April 16, 2016. The implementation strategy for the MATS rule includes emission controls, retirements, and fuel conversions to achieve compliance by the deadlines applicable to each Company unit. On June 29, 2015, the U.S. Supreme Court issued a decision finding that in developing the MATS rule the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units. On December 15, 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule to the EPA without vacatur to respond to the U.S. Supreme Court's decision. The EPA's supplemental finding in response to the U.S. Supreme Court's decision, which the EPA proposes to finalize in April 2016, is not expected to have any impact on the MATS rule compliance requirements and deadlines.

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. On October 26, 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 will recommend area designations by October 2016, and the EPA is expected to finalize them by October 2017.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS . In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard in December 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred designation decisions for certain areas in Florida.

Final revisions to the NAAQS for sulfur dioxide (SO_2) , which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has finalized a data requirements rule to support additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I having begun in 2015 and Phase II beginning in 2017. On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Florida and Georgia, but rejected all other pending challenges to the rule. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. On December 3, 2015, the EPA published a proposed revision to CSAPR that would revise existing ozone-season emissions budgets for nitrogen oxide in Mississippi and would remove Florida from the CSAPR program. The EPA proposes to finalize this rulemaking by summer 2016.

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.

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

On June 12, 2015, the EPA published a final rule requiring certain states (including Florida, Georgia, and Mississippi) to revise or remove the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM) by no later than November 22, 2016.

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. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, CSAPR, regional haze regulations, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. 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.

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 October 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

On November 3, 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 National Pollutant Discharge Elimination System 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. The ultimate impact of these requirements will depend on pending and any future legal challenges, compliance dates, and implementation of the final rule and cannot be determined at this time.

On June 29, 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 August 28, 2015, but on October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The ultimate impact of the final rule will depend on the outcome of this and other pending legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

In addition, numeric nutrient water quality standards promulgated by the State of Florida to limit the amount of nitrogen and phosphorous allowed in state waters are in effect for the State's streams and estuaries. The impact of these standards will depend on further regulatory action in connection with their site-specific implementation through the State of Florida's National Pollutant Discharge Elimination System permitting program and Total Maximum Daily Load restoration program and cannot be determined at this time.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs.

Coal Combustion Residuals

The Company currently manages CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at three electric generating plants in Florida and is a co-owner of units at generating plants located in Mississippi and Georgia operated by Mississippi Power and Georgia Power, respectively. In addition to on-site storage, the Company sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Florida, Georgia, and Mississippi 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.

On April 17, 2015, the EPA published the CCR Rule in the Federal Register, which became effective on October 19, 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. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

Based on initial cost estimates for closure in place and groundwater monitoring of ash ponds pursuant to the CCR Rule, the Company 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, 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. The Company is currently completing an analysis of the plan of closure for all ash ponds, including the timing of closure and related cost recovery through regulated rates subject to Florida PSC approval. Based on the results of that analysis, the Company may accelerate the timing of some ash pond closures which could increase its ARO liabilities from the amounts presently recorded. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. 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, 2015.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company 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. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, these liabilities have no impact to the Company's net income. 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

On October 23, 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 its review with the courts. The stay will remain in effect through the resolution of the litigation, whether resolved in the U.S. Court of Appeals for the District of Columbia Circuit or 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. 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 Company's ongoing review of the final rules; the outcome of legal challenges, including legal challenges filed by the traditional operating companies; individual state implementation of the EPA's final guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

The United Nations 21st international climate change conference took place in late 2015. The result was the adoption of 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 increasing those commitments every five years. The ultimate impact of this agreement depends on its ratification and implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2014 greenhouse gas emissions were approximately 10 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2015 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

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 operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional 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 operating companies and in some adjacent areas. The FERC directed the traditional 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 operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Retail Base Rate Case

In 2013, the Florida PSC voted to approve the 2013 Rate Case Settlement Agreement among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million annually effective January 2014 and subsequently increased base rates approximately $20 million annually effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) is accruing a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.

The 2013 Rate Case Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. For 2015 and 2014, the Company recognized reductions in depreciation expense of $20.1 million and $8.4 million , respectively.

Cost Recovery Clauses

On November 2, 2015, the Florida PSC approved the Company's 2016 annual cost recovery clause rates for its fuel, purchased power capacity, environmental, and energy conservation cost recovery clauses. The net effect of the approved changes is an expected $49 million decrease in annual revenue for 2016. The decreased revenues will not have a significant impact on net income since most of the revenues will be offset by lower expenses.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Note 1 to the financial statements under "Revenues" for additional information.

Renewables

On April 16, 2015, the Florida PSC approved three energy purchase agreements totaling 120 MWs of utility-scale solar generation located at three military installations in northwest Florida. Purchases under these solar agreements are expected to begin by early 2017. On May 5, 2015, the Florida PSC approved an energy purchase agreement for up to 178 MWs of wind generation in central Oklahoma. Purchases under these agreements began in January 2016, are for energy only, and will be recovered through the Company's fuel cost recovery mechanism.

Income Tax Matters

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 2017; 40% bonus depreciation for 2018; and 30% bonus depreciation for 2019 and for certain long-lived assets placed in service in 2020. The extension of 50% bonus depreciation is expected to result in approximately $105 million of positive cash flows for the 2015 tax year and the estimated cash flow benefit of bonus depreciation related to the PATH Act is expected to be approximately $27 million for the 2016 tax year.

Other Matters

On February 6, 2015, the Company announced plans to retire its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016, as a result of the cost to comply with environmental regulations imposed by the EPA. In connection with this retirement, the Company reclassified the net carrying value of these units from plant in service, net of depreciation, to other utility plant, net. The net book value of these units at December 31, 2015 was approximately $62 million. Subsequent to December 31, 2015, the Company filed a petition with the Florida PSC requesting permission to create a regulatory asset for the remaining net book value of Plant Smith Units 1 and 2 and the remaining inventory associated with these units as of the retirement date. The retirement of these units is not expected to have a material impact on the Company's financial statements as the Company expects to recover these amounts through its rates; however, the ultimate outcome depends on future rate proceedings with the Florida PSC and cannot be determined at this time.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, 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.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

The Company is subject to retail regulation by the Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost-based regulation by the FERC with respect to wholesale transmission rates. 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, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

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 the Company's facilities that are subject to the CCR Rule and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the 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.

As a result of the final CCR Rule discussed above, the Company recorded new AROs for facilities that are subject to the CCR Rule. The cost estimates are based on information using various assumptions related to closure in place 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, 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.

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 has 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 will decrease 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 $1 million or less change in total annual benefit expense and a $19 million or less change in projected obligations.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers,* revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances in long-term debt totaling $8 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 9 to the financial statements for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07) , effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the Company. See Note 2 to the financial statements for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid expenses of $3 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 to the financial statements for disclosures impacted by ASU 2015-17.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2015. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing facilities, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2016 through 2018, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period are primarily to maintain existing generation facilities, to add environmental modifications to existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances in the capital markets, by accessing borrowings from financial institutions, and through equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan decreased in value as of December 31, 2015 as compared to December 31, 2014. No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated during 2016. See Note 2 to the financial statements under "Pension Plans" for additional information.

Net cash provided from operating activities totaled $460 million in 2015 , an increase of $116 million from 2014 , primarily due to increases in cash flows related to clause recovery and bonus depreciation. This increase was partially offset by decreases related to the timing of fossil fuel stock purchases and vendor payments. Net cash provided from operating activities totaled $344 million in 2014 , an increase of $13 million from 2013 , primarily due to increases in cash flows related to clause recovery, partially offset by decreases in cash flows associated with voluntary contributions to the qualified pension plan.

Net cash used for investing activities totaled $281 million , $358 million , and $307 million for 2015 , 2014 , and 2013 , respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $247 million, $361 million, and $305 million for 2015 , 2014 , and 2013 , respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash used for financing activities totaled $144 million in 2015 primarily due to the payment of common stock dividends and redemptions of long-term debt, partially offset by an increase in notes payable and proceeds from the issuance of common stock to Southern Company. Net cash provided from financing activities totaled $31 million in 2014 primarily due to the issuance of long-term debt and common stock, partially offset by the payment of common stock dividends, the redemption of long-term debt and a decrease to notes payable. Net cash used for financing activities totaled $34 million in 2013 primarily due to the payment of common stock dividends and redemptions of long-term debt, partially offset by issuances of stock to Southern Company and issuances of long-term debt. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2015 included increases of $195 million in property, plant, and equipment, primarily due to additions in generation, transmission, and distribution facilities, $110 million in securities due within one year primarily due to senior notes maturing in 2016, $96 million in accumulated deferred income taxes primarily related to bonus depreciation, and $96 million in AROs. Other significant changes include decreases of $169 million in long-term debt and $37 million in under recovered regulatory clause revenues. See Note 1 and Note 5 to the financial statements for additional information regarding AROs and deferred income taxes, respectively.

The Company's ratio of common equity to total capitalization, including short-term debt, was 46.0% in 2015 and 44.7% in 2014. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, external security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

Security issuances are subject to annual regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs, including its commercial paper program which is supported by bank credit facilities.

At December 31, 2015 , the Company had approximately $74 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2015 were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2016	2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
$80	$30	$165	$275	$275	$50	$—	$50	$30

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

In November 2015, the Company amended and restated certain of its multi-year credit arrangements which, among other things, extended the maturity dates for the majority of the Company's agreements from 2016 to 2018.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross acceleration provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the Company. Such cross acceleration provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness, the payment of which was then accelerated. The Company is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

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.

Most of the unused credit arrangements with banks are allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2015 was approximately $82 million. In addition, at December 31, 2015, the Company had $33 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

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

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2015:					
Commercial paper	**$ 142**	**0.7%**	**$ 101**	**0.4%**	**$ 175**
Short-term bank debt	**—**	**—%**	**10**	**0.7%**	**40**
Total	**$ 142**	**0.7%**	**$ 111**	**0.4%**	
December 31, 2014:					
Commercial paper	$ 110	0.3%	$ 85	0.2%	$ 145
December 31, 2013:					
Commercial paper	$ 136	0.2%	$ 92	0.2%	$ 173
Short-term bank debt	—	N/A	11	1.2%	125
Total	$ 136	0.2%	$ 103	0.3%	

(*) Average and maximum amounts are based upon daily balances during the year.

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, short-term bank term loans and operating cash flows.

Financing Activities

In January 2015, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In June 2015, the Company entered into a $40 million aggregate principal amount three-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for credit support, working capital, and other general corporate purposes. The loan was repaid at maturity.

In July 2015, the Company purchased and held $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds (Gulf Power Company Project), Series 2012. These bonds were remarketed to the public on July 16, 2015.

In September 2015, the Company redeemed $60 million aggregate principal amount of its Series L 5.65% Senior Notes due September 1, 2035.

In October 2015, the Company entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $80 million.

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

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, transmission, and energy price risk management.

The maximum potential collateral requirements under these contracts at December 31, 2015 were as follows:

Credit Ratings		Maximum Potential Collateral Requirements
		(in millions)
At BBB- and/or Baa3	$	91
Below BBB- and/or Baa3	$	467

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, 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 August 17, 2015, S&P downgraded the consolidated long-term issuer rating of Southern Company (including the Company) to A- from A and revised its credit rating outlook from negative to stable. Separately, on August 24, 2015, S&P revised its credit rating outlook from stable to negative following the announcement of the proposed merger of a wholly-owned direct subsidiary of Southern Company with and into AGL Resources Inc.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $82 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2016 was 0.03%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would not materially affect annualized interest expense at January 1, 2016. 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 fuel and electricity prices, the Company enters into financial hedge contracts for natural gas purchases and physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Florida PSC and the actual cost of fuel is recovered through the retail fuel clause. The Company had no material change in market risk exposure for the year ended December 31, 2015 when compared to the year ended December 31, 2014.

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, substantially all of which are composed of regulatory hedges, were as follows:

		2015 Changes		2014 Changes
	Fair Value			
	(in millions)			
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$**	**(72)**	$	(10)
Contracts realized or settled		**47**		(3)
Current period changes (*)		**(75)**		(59)
Contracts outstanding at the end of the period, assets (liabilities), net	**$**	**(100)**	$	(72)

(*) 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 were 82 million mmBtu and 85 million mmBtu as of December 31, 2015 and December 31, 2014, respectively.

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The weighted average swap contract cost above market prices was approximately $1.17 per mmBtu as of December 31, 2015 and $0.80 per mmBtu as of December 31, 2014. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2015 and 2014, 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 fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented and the actual cost of fuel is recovered through the retail fuel 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. 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, 2015 were as follows:

	Fair Value Measurements December 31, 2015			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(100)	(49)	(46)	(5)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (100)	$ (49)	$ (46)	$ (5)

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.

Through 2015, capacity revenues represented the majority of the Company's wholesale earnings. The Company had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 and these capacity revenues represented 82% of total wholesale capacity revenues for 2015. Due to the expiration of a wholesale contract at the end of 2015 and future expiration dates of the remaining wholesale contracts for the unit, the Company currently has contracts to cover 34% of the unit for 2016 and 27% of the unit through 2019. Although the Company is actively evaluating alternatives relating to this asset, including replacement wholesale contracts, the expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts will have a material negative impact on the Company's earnings in 2016 and may continue to have a material negative impact in future years. In the event some portion of the Company's ownership of Plant Scherer Unit 3 is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the Southern Company power pool or into the wholesale market.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $215 million for 2016 , $197 million for 2017 , and $176 million for 2018 . These amounts include capital expenditures related to contractual purchase commitments for capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $30 million, $43 million, and $44 million for 2016 , 2017 , and 2018 , respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure in place and ground water monitoring of ash ponds at Plant Scholz and in accordance with the CCR Rule, which are not reflected in the capital expenditures above as these costs are associated with 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, are estimated to be $16 million, $15 million, and $47 million for the years 2016, 2017, and 2018, 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 the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

Contractual Obligations

	2016	2017-2018	2019-2020	After 2020	Total
			(in millions)		
Long-term debt [(a)] –					
Principal	$ 110	$ 85	$ 175	$ 949	$ 1,319
Interest	54	92	87	755	988
Financial derivative obligations [(b)]	49	46	5	—	100
Preference stock dividends [(c)]	9	18	18	—	45
Operating leases [(d)]	10	11	—	—	21
Purchase commitments –					
Capital [(e)]	188	373	—	—	561
Fuel [(f)]	219	287	178	107	791
Purchased power [(g)]	115	234	241	910	1,500
Other [(h)]	14	32	34	156	236
Pension and other postretirement benefit plans [(i)]	5	11	—	—	16
Total	$ 773	$ 1,189	$ 738	$ 2,877	$ 5,577

(a) All amounts are reflected based on final maturity dates. 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, 2016, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

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

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

(d) Excludes a PPA accounted for as a lease and is included in purchased power.

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures associated with environmental regulations. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected in "Other." At December 31, 2015, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(f) 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, 2015.

(g) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity clause. Energy costs associated with PPAs are recovered through the fuel clause. See Notes 3 and 7 to the financial statements for additional information.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices. Limestone costs are recovered through the environmental cost recovery clause. See Note 3 to the financial statements for additional information.

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

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Cautionary Statement Regarding Forward-Looking Statements

The Company's 2015 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, 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, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, estimated sales and purchases under power sale and purchase agreements, 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 legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, 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, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including , without limitation, IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the 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 and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards ;
- 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;
- 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 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, 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.

STATEMENTS OF INCOME
For the Years Ended December 31, 2015 , 2014 , and 2013
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	2015	2014	2013
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 1,249**	$ 1,267	$ 1,170
Wholesale revenues, non-affiliates	**107**	129	109
Wholesale revenues, affiliates	**58**	130	100
Other revenues	**69**	64	61
Total operating revenues	**1,483**	1,590	1,440
Operating Expenses:			
Fuel	**445**	605	533
Purchased power, non-affiliates	**100**	82	52
Purchased power, affiliates	**35**	25	33
Other operations and maintenance	**354**	341	310
Depreciation and amortization	**141**	145	149
Taxes other than income taxes	**118**	111	98
Total operating expenses	**1,193**	1,309	1,175
Operating Income	**290**	281	265
Other Income and (Expense):			
Allowance for equity funds used during construction	**13**	12	6
Interest expense, net of amounts capitalized	**(49)**	(53)	(56)
Other income (expense), net	**(5)**	(3)	(3)
Total other income and (expense)	**(41)**	(44)	(53)
Earnings Before Income Taxes	**249**	237	212
Income taxes	**92**	88	80
Net Income	**157**	149	132
Dividends on Preference Stock	**9**	9	8
Net Income After Dividends on Preference Stock	**$ 148**	$ 140	$ 124

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2015 , 2014 , and 2013
Gulf Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Net Income	**$ 157**	$ 149	$ 132
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $-, respectively	**1**	—	—
Reclassification adjustment for amounts included in net income, net of tax of $-, $-, and $-, respectively	**—**	—	1
Total other comprehensive income (loss)	**1**	—	1
Comprehensive Income	**$ 158**	$ 149	$ 133

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2015 , 2014 , and 2013
Gulf Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Activities:			
Net income	$ 157	$ 149	$ 132
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	152	153	156
Deferred income taxes	90	65	77
Allowance for equity funds used during construction	(13)	(12)	(6)
Pension, postretirement, and other employee benefits	10	(23)	11
Other, net	7	2	9
Changes in certain current assets and liabilities —			
-Receivables	33	(17)	(49)
-Fossil fuel stock	(6)	34	19
-Prepaid income taxes	32	(19)	16
-Other current assets	(2)	(2)	(1)
-Accounts payable	(22)	8	(7)
-Accrued compensation	2	11	(3)
-Over recovered regulatory clause revenues	22	—	(17)
-Other current liabilities	(2)	(5)	(6)
Net cash provided from operating activities	460	344	331
Investing Activities:			
Property additions	(235)	(348)	(293)
Cost of removal net of salvage	(10)	(13)	(14)
Change in construction payables	(28)	12	7
Payments pursuant to long-term service agreements	(8)	(8)	(7)
Other investing activities	—	(1)	—
Net cash used for investing activities	(281)	(358)	(307)
Financing Activities:			
Increase (decrease) in notes payable, net	32	(26)	12
Proceeds —			
Common stock issued to parent	20	50	40
Capital contributions from parent company	4	4	3
Preference stock	—	—	50
Pollution control revenue bonds	13	42	63
Senior notes	—	200	90
Redemptions —			
Pollution control revenue bonds	(13)	(29)	(76)
Senior notes	(60)	(75)	(90)
Payment of preference stock dividends	(9)	(9)	(7)
Payment of common stock dividends	(130)	(123)	(115)
Other financing activities	(1)	(3)	(4)
Net cash provided from (used for) financing activities	(144)	31	(34)
Net Change in Cash and Cash Equivalents	35	17	(10)
Cash and Cash Equivalents at Beginning of Year	39	22	32
Cash and Cash Equivalents at End of Year	$ 74	$ 39	$ 22
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $6, $5, and $3 capitalized, respectively)	$ 52	$ 48	$ 53
Income taxes (net of refunds)	(7)	44	(11)

Noncash transactions — accrued property additions at year-end	**20**	42	32

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

BALANCE SHEETS
At December 31, 2015 and 2014
Gulf Power Company 2015 Annual Report

Assets	**2015**	2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 74**	$ 39
Receivables —		
Customer accounts receivable	**76**	73
Unbilled revenues	**54**	58
Under recovered regulatory clause revenues	**20**	57
Other accounts and notes receivable	**9**	8
Affiliated companies	**1**	10
Accumulated provision for uncollectible accounts	**(1)**	(2)
Income taxes receivable, current	**27**	—
Fossil fuel stock, at average cost	**108**	101
Materials and supplies, at average cost	**56**	56
Other regulatory assets, current	**90**	74
Prepaid expenses	**8**	37
Other current assets	**14**	2
Total current assets	**536**	513
Property, Plant, and Equipment:		
In service	**5,045**	4,495
Less accumulated provision for depreciation	**1,296**	1,296
Plant in service, net of depreciation	**3,749**	3,199
Other utility plant, net	**62**	—
Construction work in progress	**48**	465
Total property, plant, and equipment	**3,859**	3,664
Other Property and Investments	**4**	15
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**61**	56
Other regulatory assets, deferred	**427**	416
Other deferred charges and assets	**33**	33
Total deferred charges and other assets	**521**	505
Total Assets	**$ 4,920**	$ 4,697

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

BALANCE SHEETS
At December 31, 2015 and 2014
Gulf Power Company 2015 Annual Report

Liabilities and Stockholder's Equity	**2015**	2014
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 110**	$ —
Notes payable	**142**	110
Accounts payable —		
Affiliated	**55**	87
Other	**44**	56
Customer deposits	**36**	35
Accrued taxes —		
Accrued income taxes	**4**	—
Other accrued taxes	**9**	9
Accrued interest	**9**	11
Accrued compensation	**25**	23
Deferred capacity expense, current	**22**	22
Other regulatory liabilities, current	**22**	1
Liabilities from risk management activities	**49**	37
Other current liabilities	**40**	22
Total current liabilities	**567**	413
Long-Term Debt (See accompanying statements)	**1,193**	1,362
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**893**	797
Employee benefit obligations	**129**	121
Deferred capacity expense	**141**	163
Asset retirement obligations	**113**	17
Other cost of removal obligations	**233**	235
Other regulatory liabilities, deferred	**47**	48
Other deferred credits and liabilities	**102**	85
Total deferred credits and other liabilities	**1,658**	1,466
Total Liabilities	**3,418**	3,241
Preference Stock (See accompanying statements)	**147**	147
Common Stockholder's Equity (See accompanying statements)	**1,355**	1,309
Total Liabilities and Stockholder's Equity	**$ 4,920**	$ 4,697
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2015 and 2014
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	2015	2014	2015	2014
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
5.30% due 2016	**$ 110**	$ 110		
5.90% due 2017	**85**	85		
4.75% due 2020	**175**	175		
3.10% to 5.75% due 2022-2051	**640**	700		
Total long-term notes payable	**1,010**	1,070		
Other long-term debt —				
Pollution control revenue bonds —				
0.55% to 4.45% due 2022-2049	**227**	240		
Variable rates (0.01% to 0.12% at 1/1/16) due 2022-2042	**82**	69		
Total other long-term debt	**309**	309		
Unamortized debt discount	**(8)**	(9)		
Unamortized debt issuance expense	**(8)**	(8)		
Total long-term debt (annual interest requirement — $54 million)	**1,303**	1,362		
Less amount due within one year	**110**	—		
Long-term debt excluding amount due within one year	**1,193**	1,362	**44.3%**	48.3%
Preferred and Preference Stock:				
Authorized — 20,000,000 shares — preferred stock				
— 10,000,000 shares — preference stock				
Outstanding — $100 par or stated value				
— 6% preference stock — 550,000 shares (non-cumulative)	**54**	54		
— 6.45% preference stock — 450,000 shares (non-cumulative)	**44**	44		
— 5.60% preference stock — 500,000 shares (non-cumulative)	**49**	49		
Total preference stock (annual dividend requirement — $9 million)	**147**	147	**5.4**	5.2
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 2015: 5,642,717 shares				
— 2014: 5,442,717 shares	**503**	483		
Paid-in capital	**567**	560		
Retained earnings	**285**	267		
Accumulated other comprehensive loss	**—**	(1)		
Total common stockholder's equity	**1,355**	1,309	**50.3**	46.5
Total Capitalization	**$ 2,695**	$ 2,818	**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, 2015 , 2014 , and 2013
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2012	5	$ 393	$ 549	$ 241	$ (2)	$ 1,181
Net income after dividends on preference stock	—	—	—	124	—	124
Issuance of common stock	—	40	—	—	—	40
Capital contributions from parent company	—	—	4	—	—	4
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(115)	—	(115)
Balance at December 31, 2013	5	433	553	250	(1)	1,235
Net income after dividends on preference stock	—	—	—	140	—	140
Issuance of common stock	—	50	—	—	—	50
Capital contributions from parent company	—	—	7	—	—	7
Cash dividends on common stock	—	—	—	(123)	—	(123)
Balance at December 31, 2014	**5**	**483**	**560**	**267**	**(1)**	**1,309**
Net income after dividends on preference stock	**—**	**—**	**—**	**148**	**—**	**148**
Issuance of common stock	**1**	**20**	**—**	**—**	**—**	**20**
Capital contributions from parent company	**—**	**—**	**7**	**—**	**—**	**7**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**1**	**1**
Cash dividends on common stock	**—**	**—**	**—**	**(130)**	**—**	**(130)**
Balance at December 31, 2015	**6**	**$ 503**	**$ 567**	**$ 285**	**$ —**	**$ 1,355**

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

NOTES TO FINANCIAL STATEMENTS
Gulf Power Company 2015 Annual Report

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

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

The equity method is used for entities in which the Company has significant influence but does not control.

The Company is subject to regulation by the FERC and the Florida 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

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers,* revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances in long-term debt totaling $8 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 9 for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07) *,* effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the Company. See Note 2 for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid expenses of $3 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 for disclosures impacted by ASU 2015-17.

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 $81 million , $80 million , and $78 million during 2015 , 2014 , and 2013 , 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 operating agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $12 million , $9 million , and $10 million and Mississippi Power $27 million , $31 million , and $17 million in 2015 , 2014 , and 2013 , respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company has an agreement with Alabama Power under which Alabama Power has made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA from a combined cycle plant located in Alabama. The transmission improvements were completed in 2014. The Company expects to pay Alabama Power approximately $12 million a year from 2016 through 2023 for these improvements. Payments by the Company to Alabama Power were $14 million , $12 million , and $8 million in 2015 , 2014 , and 2013 , respectively, for the improvements. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2015 , 2014 , or 2013 .

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

NOTES (continued)
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Regulatory Assets and Liabilities

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

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

	2015	2014	Note
	(in millions)		
PPA charges	**$ 163**	$ 185	(j,k)
Retiree benefit plans, net	**147**	148	(i,j)
Fuel-hedging assets, net	**104**	73	(g,j)
Deferred income tax charges	**59**	53	(a)
Environmental remediation	**46**	48	(h,j)
Regulatory asset, offset to other cost of removal	**29**	8	(m)
Closure of Plant Scholz ash pond	**29**	—	(h,j)
Loss on reacquired debt	**15**	16	(c)
Vacation pay	**10**	10	(d,j)
Deferred return on transmission upgrades	**10**	—	(m)
Other regulatory assets, net	**7**	9	(l)
Deferred income tax charges — Medicare subsidy	**2**	3	(b)
Under recovered regulatory clause revenues	**1**	53	(e)
Other cost of removal obligations	**(262)**	(243)	(a)
Property damage reserve	**(38)**	(35)	(f)
Over recovered regulatory clause revenues	**(22)**	—	(e)
Deferred income tax credits	**(3)**	(4)	(a)
Asset retirement obligations, net	**(1)**	(5)	(a,j)
Total regulatory assets (liabilities), net	**$ 296**	$ 319	

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

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years . Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered and amortized over periods not exceeding 14 years .

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years .

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

(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year .

(f) Recorded and recovered or amortized as approved by the Florida PSC.

(g) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed five years . Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clause.

(h) Recovered through the environmental cost recovery clause when the remediation or the work is performed.

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

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

(k) Recovered over the life of the PPA for periods up to eight years .

(l) Comprised primarily of net book value of retired meters and recovery of injuries and damages costs. These costs are recorded and recovered or amortized as approved by the Florida PSC, generally over periods not exceeding eight years .

(m) Recorded as authorized by the Florida PSC in the settlement agreement approved in December 2013 (2013 Rate Case Settlement Agreement). See Note 3 for additional information.

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

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida 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. Federal ITCs utilized are deferred and amortized to income over the average life of the related property and state ITCs are recognized in the period in which the credit is claimed on the state income tax return. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

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.

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

	2015	2014
	(in millions)	
Generation	**$ 2,974**	$ 2,638
Transmission	**691**	516
Distribution	**1,196**	1,157
General	**182**	182
Plant acquisition adjustment	**2**	2
Total plant in service	**$ 5,045**	$ 4,495

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 as incurred or performed.

On February 6, 2015, the Company announced plans to retire its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016, as a result of the cost to comply with environmental regulations imposed by the EPA. In connection with this retirement, the Company reclassified the net carrying value of these units from plant in service, net of depreciation, to other utility plant, net. The net book value of these units at December 31, 2015 was approximately $62 million .

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.5% in 2015 and 3.6% in both 2014 and 2013 . Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. As authorized by the Florida PSC in the 2013 Rate Case Settlement Agreement, the Company is allowed to reduce depreciation and record a regulatory asset in an aggregate amount up to $62.5 million between January 2014 and June 2017. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) 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 an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability 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 on April 17, 2015 (CCR Rule), principally ash ponds, and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the 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 Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

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

	2015	2014
	(in millions)	
Balance at beginning of year	**$ 17**	$ 16
Liabilities incurred	**105**	—
Liabilities settled	**(1)**	—
Accretion	**2**	1
Cash flow revisions	**7**	—
Balance at end of year	**$ 130**	$ 17

The increase in liabilities incurred in 2015 is primarily related to AROs associated with the portion of the Company's steam generation facilities impacted by the CCR Rule. The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2015 using various assumptions related to closure in place 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, 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.

In connection with permitting activity related to the coal ash pond at the retired Plant Scholz facility, the Company recorded additional AROs of $29 million .

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 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 calculating taxable income. The average annual AFUDC rate was 5.73% for both 2015 and 2014 and 6.26% for 2013 . AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 10.80% , 10.93% , and 6.87% for 2015 , 2014 , and 2013 , respectively.

Impairment of Long-Lived Assets and Intangibles

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

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million , with a target level for the reserve between $48 million and $55 million . The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2015 , 2014 , and 2013 . As of December 31, 2015 and 2014 , the balance in the Company's property damage reserve totaled approximately $38 million and $35 million , respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. As authorized in the 2013 Rate Case Settlement Agreement, the Company may recover costs associated with any tropical systems named by the National Hurricane Center through the initiation of a storm surcharge. The storm surcharge will begin, on an interim basis, 60 days following the filing of a cost recovery petition. The storm surcharge generally may not exceed $4.00 / 1,000 KWHs on monthly residential bills in aggregate for a calendar year. This limitation does not apply if the Company incurs in excess of $100 million in storm recovery costs that qualify for recovery in a given calendar year. This threshold amount is inclusive of the amount necessary to replenish the storm reserve to the level that existed as of December 31, 2013. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional details of the 2013 Rate Case Settlement Agreement.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was zero at December 31, 2015 and had a balance of $4.0 million at December 31, 2014 . Included in current liabilities and deferred credits and other liabilities in the balance sheets at December 31, 2014 is $1.6 million and $2.4 million , respectively. The Company recorded a liability with a corresponding regulatory asset of $1.7 million for estimated liabilities related to outstanding claims and suits in excess of the reserve balance at December 31, 2015 , of which $1.6 million and $0.1 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. There were no liabilities in excess of the reserve balance at December 31, 2014 .

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of oil, natural gas, coal, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. 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, and electricity purchases and sales. 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 fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts 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 income. 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.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2015 .

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

Comprehensive Income

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

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2016 . 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, 2016 , 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:	2015	2014	2013
Pension plans			
Discount rate – interest costs	**4.18%**	5.02%	4.27%
Discount rate – service costs	**4.48**	5.02	4.27
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**3.59**	3.59	3.59
Other postretirement benefit plans			
Discount rate – interest costs	**4.04%**	4.86%	4.06%
Discount rate – service costs	**4.38**	4.86	4.06
Expected long-term return on plan assets	**8.07**	8.08	8.04
Annual salary increase	**3.59**	3.59	3.59

Assumptions used to determine benefit obligations:	2015	2014
Pension plans		
Discount rate	**4.71%**	4.18%
Annual salary increase	**4.46**	3.59
Other postretirement benefit plans		
Discount rate	**4.51%**	4.04%
Annual salary increase	**4.46**	3.59

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

For purposes of its December 31, 2015 measurement date, the Company adopted new mortality tables for its pension and other postretirement benefit plans, which reflect decreased life expectancies in the U.S. The adoption of new mortality tables reduced the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $9 million and $1 million , respectively.

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, 2015 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2024
Post-65 medical	5.50	4.50	2024
Post-65 prescription	10.00	4.50	2025

NOTES (continued)
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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, 2015 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 4	$ (3)
Service and interest costs	—	—

Pension Plans

The total accumulated benefit obligation for the pension plans was $424 million at December 31, 2015 and $438 million at December 31, 2014 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 491**	$ 395
Service cost	**12**	10
Interest cost	**20**	19
Benefits paid	**(20)**	(16)
Actuarial loss (gain)	**(23)**	83
Balance at end of year	**480**	491
Change in plan assets		
Fair value of plan assets at beginning of year	**435**	386
Actual return on plan assets	**4**	34
Employer contributions	**1**	31
Benefits paid	**(20)**	(16)
Fair value of plan assets at end of year	**420**	435
Accrued liability	**$ (60)**	$ (56)

At December 31, 2015 , the projected benefit obligations for the qualified and non-qualified pension plans were $457 million and $23 million , respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's pension plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 142**	$ 146
Current liabilities, other	**(1)**	(1)
Employee benefit obligations	**(59)**	(55)

NOTES (continued)
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Presented below are the amounts included in regulatory assets at December 31, 2015 and 2014 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 2016 .

	2015	2014	Estimated Amortization in 2016
		(in millions)	
Prior service cost	**$ 2**	$ 3	**$ 1**
Net loss	**140**	143	**6**
Regulatory assets	**$ 142**	$ 146	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 146**	$ 75
Net (gain) loss	**6**	77
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	(1)
Amortization of net gain (loss)	**(9)**	(5)
Total reclassification adjustments	**(10)**	(6)
Total change	**(4)**	71
Ending balance	**$ 142**	$ 146

Components of net periodic pension cost were as follows:

	2015	2014	2013
		(in millions)	
Service cost	**$ 12**	$ 10	$ 11
Interest cost	**20**	19	17
Expected return on plan assets	**(32)**	(28)	(26)
Recognized net loss	**9**	5	9
Net amortization	**1**	1	1
Net periodic pension cost	**$ 10**	$ 7	$ 12

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.

NOTES (continued)
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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, 2015 , estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2016	$ 19
2017	20
2018	21
2019	22
2020	24
2021 to 2025	139

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 78**	$ 69
Service cost	**1**	1
Interest cost	**3**	3
Benefits paid	**(4)**	(4)
Actuarial loss (gain)	**(1)**	11
Plan amendment	**4**	(2)
Retiree drug subsidy	**—**	—
Balance at end of year	**81**	78
Change in plan assets		
Fair value of plan assets at beginning of year	**18**	17
Actual return on plan assets	**—**	2
Employer contributions	**3**	3
Benefits paid	**(4)**	(4)
Fair value of plan assets at end of year	**17**	18
Accrued liability	**$ (64)**	$ (60)

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's other postretirement benefit plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 10**	$ 6
Current liabilities, other	**(1)**	(1)
Other regulatory liabilities, deferred	**(5)**	(4)
Employee benefit obligations	**(63)**	(59)

NOTES (continued)
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Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2015 and 2014 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2016 .

	2015	2014	Estimated Amortization in 2016
		(in millions)	
Prior service cost	$ —	$ (2)	$ —
Net loss	5	4	—
Net regulatory assets (liabilities)	$ 5	$ 2	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	$ 2	$ (7)
Net (gain) loss	1	11
Change in prior service costs	2	(2)
Reclassification adjustments:		
Amortization of prior service costs	—	—
Amortization of net gain (loss)	—	—
Total reclassification adjustments	—	—
Total change	3	9
Ending balance	$ 5	$ 2

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

	2015	2014	2013
		(in millions)	
Service cost	$ 1	$ 1	$ 1
Interest cost	3	3	3
Expected return on plan assets	(1)	(1)	(1)
Net amortization	—	—	—
Net periodic postretirement benefit cost	$ 3	$ 3	$ 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)	
2016	$ 5	$ —	$ 5
2017	5	—	5
2018	6	—	6
2019	6	(1)	5
2020	6	(1)	5
2021 to 2025	29	(3)	26

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. 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, 2015 and 2014 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2015**	2014
Pension plan assets:			
Domestic equity	26%	**30%**	30%
International equity	25	**23**	23
Fixed income	23	**23**	27
Special situations	3	**2**	1
Real estate investments	14	**16**	14
Private equity	9	**6**	5
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	25%	**29%**	29%
International equity	24	**22**	22
Domestic fixed income	25	**25**	29
Special situations	3	**2**	1
Real estate investments	14	**16**	14
Private equity	9	**6**	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, 2015 and 2014 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

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

NOTES (continued)
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The fair values of pension plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

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*	$ 73	$ 31	$ —	$ —	$ 104
International equity*	54	45	—	—	99
Fixed income:					
U.S. Treasury, government, and agency bonds	—	21	—	—	21
Mortgage- and asset-backed securities	—	9	—	—	9
Corporate bonds	—	51	—	—	51
Pooled funds	—	23	—	—	23
Cash equivalents and other	—	7	—	—	7
Real estate investments	14	—	—	55	69
Private equity	—	—	—	29	29
Total	$ 141	$ 187	$ —	$ 84	$ 412

* 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.

NOTES (continued)
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	Fair Value Measurements Using				
As of December 31, 2014:	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*	$ 77	$ 32	$ —	$ —	$ 109
International equity*	48	44	—	—	92
Fixed income:					
U.S. Treasury, government, and agency bonds	—	31	—	—	31
Mortgage- and asset-backed securities	—	8	—	—	8
Corporate bonds	—	51	—	—	51
Pooled funds	—	23	—	—	23
Cash equivalents and other	—	30	—	—	30
Real estate investments	13	—	—	50	63
Private equity	—	—	—	26	26
Total	$ 138	$ 219	$ —	$ 76	$ 433

* 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.

NOTES (continued)
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The fair values of other postretirement benefit plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 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	—	1	—	—	1
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	1	—	—	—	1
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$ 7	$ 7	$ —	$ 3	$ 17

* 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, 2014:	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*	$ 3	$ 1	$ —	$ —	$ 4
International equity*	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	1	—	—	1
Mortgage- and asset-backed securities	—	1	—	—	1
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	—	1	—	—	1
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$ 6	$ 9	$ —	$ 3	$ 18

* 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 2015 , 2014 , and 2013 were $4 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 received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2015 , the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $46 million , of which approximately $4 million is included in under recovered regulatory clause revenues and other current liabilities and approximately $42 million is included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

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

FERC Matters

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 operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional 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 operating companies and in some adjacent areas. The FERC directed the traditional 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 operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

In 2013, the Florida PSC voted to approve the 2013 Rate Case Settlement Agreement among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million annually effective January 2014 and subsequently increased base rates approximately $20 million annually effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) is accruing a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.

The 2013 Rate Case Settlement Agreement also includes a self-executing adjustment mechanism that will increase the authorized retail ROE midpoint and range by 25 basis points in the event the 30 -year treasury yield rate increases by an average of at least 75 basis points above 3.7947% for a consecutive six -month period.

The 2013 Rate Case Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. For 2015 and 2014, the Company recognized reductions in depreciation expense of $20.1 million and $8.4 million , respectively.

Pursuant to the 2013 Rate Case Settlement Agreement, the Company may not request an increase in its retail base rates to be effective until after June 2017, unless the Company's actual retail ROE falls below the authorized ROE range.

Cost Recovery Clauses

On November 2, 2015, the Florida PSC approved the Company's annual rate clause request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2016. The net effect of the approved changes is an expected $49 million decrease in annual revenue for 2016. The decreased revenues will not have a significant impact on net income since most of the revenues will be offset by lower expenses.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested.

At December 31, 2015 , the over recovered fuel balance was approximately $18 million , which is included in other regulatory liabilities, current in the balance sheets. At December 31, 2014 , the under recovered fuel balance was approximately $40 million , which is included in under recovered regulatory clause revenues in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2015 and 2014, the under recovered purchased power capacity balance was immaterial.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2015 , the under recovered environmental balance was immaterial. At December 31, 2014 , the under recovered environmental balance was approximately $10 million , which is included in under recovered regulatory clause revenues in the balance sheets.

In 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in November 2015. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The total cost of the project was approximately $653 million , with the Company's portion being approximately $316 million , excluding AFUDC. The Company's portion of the cost is being recovered through the environmental cost recovery clause.

Energy Conservation Cost Recovery

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

At December 31, 2015 , the over recovered ECCR balance was approximately $4 million , which is included in other regulatory liabilities, current in the balance sheet. At December 31, 2014 , the under recovered ECCR balance was approximately $3 million , which is included in under recovered regulatory clause revenues in the balance sheet.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 MWs capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

At December 31, 2015 , the Company's percentage ownership and investment in these jointly-owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in millions)	
Plant in service	$ 395	$ 669
Accumulated depreciation	136	184
Construction work in progress	2	9
Company Ownership	25%	50%

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

5. INCOME TAXES

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:

	2015	2014	2013
		(in millions)	
Federal -			
Current	**$ (3)**	$ 23	$ 5
Deferred	**80**	52	63
	77	75	68
State -			
Current	**5**	—	(2)
Deferred	**10**	13	14
	15	13	12
Total	**$ 92**	$ 88	$ 80

NOTES (continued)
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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:

	2015	2014
	(in millions)	
Deferred tax liabilities-		
Accelerated depreciation	**$ 812**	$ 777
Property basis differences	**133**	52
Fuel recovery clause	**—**	16
Pension and other employee benefits	**39**	34
Regulatory assets associated with employee benefit obligations	**59**	60
Regulatory assets associated with asset retirement obligations	**40**	7
Other	**26**	22
Total	**1,109**	968
Deferred tax assets-		
Federal effect of state deferred taxes	**33**	31
Postretirement benefits	**26**	18
Pension and other employee benefits	**65**	66
Property reserve	**15**	13
Asset retirement obligations	**40**	7
Alternative minimum tax carryforward	**18**	18
Other	**19**	18
Total	**216**	171
Accumulated deferred income taxes	**$ 893**	$ 797

On November 20, 2015, the FASB issued ASU 2015-17, which simplifies the presentation of deferred income taxes. The new guidance resulted in a reclassification from prepaid expenses of $3 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. See Note 1 under "Recently Issued Accounting Standards" for additional information.

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation in 2015 and 2014.

At December 31, 2015 , tax-related regulatory assets to be recovered from customers were $61 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, 2015 , the tax-related regulatory liabilities to be credited to customers were $3 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 average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to approximately $1 million annually for 2015 , 2014 , and 2013 . At December 31, 2015 , all ITCs available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

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

	2015	2014	2013
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.9**	3.5	3.5
Non-deductible book depreciation	**0.5**	0.4	0.5
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.1)	(0.2)
AFUDC equity	**(1.8)**	(1.8)	(1.1)
Other, net	**(0.6)**	0.1	(0.1)
Effective income tax rate	**36.9%**	37.1%	37.6%

Unrecognized Tax Benefits

The Company has no material unrecognized tax benefits for 2015 or 2014. The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial and the Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances, but an estimate of the range of reasonably possible outcomes cannot be determined at this time.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 and 2014 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.

6. FINANCING

Securities Due Within One Year

At December 31, 2015 , the Company had $110 million of long-term debt due within one year.

Maturities from 2017 through 2020 applicable to total long-term debt are as follows: $85 million in 2017 and $175 million in 2020. There are no scheduled maturities in 2018 or 2019.

Senior Notes

At each of December 31, 2015 and 2014 , the Company had a total of $1.01 billion and $1.07 billion of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totaled approximately $41 million at both December 31, 2015 and 2014.

In September 2015, the Company redeemed $60 million aggregate principal amount of Series L 5.65% Senior Notes due September 1, 2035.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2015 and 2014 was $309 million .

In July 2015, the Company purchased and held $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds (Gulf Power Company Project), Series 2012. The Company remarketed these bonds to the public on July 16, 2015.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2015 . The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, certain series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2015, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million . The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an aggregate outstanding principal amount of $41 million as of December 31, 2015 . There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At December 31, 2015 , committed credit arrangements with banks were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2016	**2017**	**2018**	**Total**	**Unused**	**One Year**	**Two Years**	**Term Out**	**No Term Out**
(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
$ 80	$ 30	$ 165	$ 275	$ 275	$ 50	$ —	$ 50	$ 30

In November 2015, the Company amended and restated certain of its multi-year credit arrangements which, among other things, extended the maturity dates for the majority of the Company's agreements from 2016 to 2018.

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.

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.

Most of these bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2015 , the Company was in compliance with these covenants.

Most of the $275 million of unused credit arrangements with banks provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2015 was approximately $82 million . In addition, at December 31, 2015, the Company had $33 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Commercial Paper at the End of the Period		
	Amount Outstanding		Weighted Average Interest Rate
	(in millions)		
December 31, 2015	**$**	**142**	**0.7%**
December 31, 2014	$	110	0.3%

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 2015 , 2014 , and 2013 , the Company incurred fuel expense of $445 million , $605 million , and $533 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.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under purchased power agreements accounted for as operating leases was $75 million , $50 million , and $21 million for 2015 , 2014 , and 2013 , respectively.

Estimated total minimum long-term commitments at December 31, 2015 were as follows:

	Operating Lease PPAs	
	(in millions)	
2016	$	79
2017		79
2018		79
2019		79
2020		79
2021 and thereafter		191
Total	$	586

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 operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the operating lease PPAs discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $14 million , $15 million , and $18 million for 2015 , 2014 , and 2013 , respectively.

Estimated total minimum lease payments under these operating leases at December 31, 2015 were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
	(in millions)		
2016	$ 9	$ 1	$ 10
2017	6	1	7
2018	4	—	4
Total	$ 19	$ 2	$ 21

The Company and Mississippi Power jointly entered into an operating lease agreement for aluminum railcars for the transportation of coal to 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 and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, was $2 million in 2015 , and $3 million in both 2014 and 2013 . The Company's annual railcar lease payments for 2016 and 2017 will average approximately $1 million each year. There are no lease payment obligations for the period 2018 and thereafter.

In addition to railcar leases, the Company has operating lease agreements for barges and towboats for the transport of coal to Plants Crist and Smith. The Company has the option to renew the leases at the end of the lease term. The Company's lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, were $10 million in both 2015 and 2014 and $12 million in 2013. The Company's annual barge and towboat payments for 2016 through 2018 will average approximately $5 million each year.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation, in the form of Southern Company stock options and 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, 2015 , there were 198 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. As a result, stock-based compensation granted to employees in 2015 consisted exclusively of performance share units.

For the years ended December 31, 2014 and 2013 , employees of the Company were granted stock options for 432,371 shares and 285,209 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014 and 2013 derived using the Black-Scholes stock option pricing model was $2.20 and $2.93 , respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented. As of December 31, 2015 , 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, 2015 , 2014 , and 2013 was $2 million , $5 million , and $2 million , respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1 million , $2 million , and $1 million for the years ended December 31, 2015 , 2014 , and 2013 , respectively. As of December 31, 2015 , the aggregate intrinsic value for the options outstanding and options exercisable was $7 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 which equates to the requisite service period for accounting purposes. 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, issued in 2015, 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, 2015 , 2014 , and 2013 , employees of the Company were granted performance share units of 48,962 , 37,829 , and 30,627 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2015 , 2014 , and 2013 , 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 $46.38 , $37.54 , and $40.50 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2015 was $47.75 .

For the years ended December 31, 2015 , 2014 , and 2013 , total compensation cost for performance share units recognized in income was $2 million , $1 million , and $1 million , respectively. The related tax benefit also recognized in income was $1 million in 2015 and immaterial in 2014 and 2013. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2015 , there was $2 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 19 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, 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:				
Interest rate derivatives	$ —	$ 1	$ —	$ 1
Cash equivalents	18	—	—	18
Total	$ 18	$ 1	$ —	$ 19
Liabilities:				
Energy-related derivatives	$ —	$ 100	$ —	$ 100

As of December 31, 2014 , 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, 2014:	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	$ 18	$ —	$ —	$ 18
Liabilities:				
Energy-related derivatives	$ —	$ 72	$ —	$ 72

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflect the net present value of expected payments and receipts under the swap agreement based on the market’s expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2015 and 2014 , 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:		
2015	**$ 1,303**	**$ 1,339**
2014	$ 1,362	$ 1,477

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 available 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 may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. 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 commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

Energy-related derivative contracts are accounted for under one of two methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2015 , the net volume of energy-related derivative contracts for natural gas positions totaled 82 million mmBtu for the Company, with the longest hedge date of 2020 over which it 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 earnings.

At December 31, 2015 , the following interest rate derivative was outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2015
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$ 80	3-month LIBOR	2.32%	December 2026	$ 1

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2016 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2026 .

Derivative Financial Statement Presentation and Amounts

At December 31, 2015 and 2014 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ —**	$ —	Liabilities from risk management activities	**$ 49**	$ 37
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**51**	35
Total derivatives designated as hedging instruments for regulatory purposes		**$ —**	$ —		**$ 100**	$ 72
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	**$ 1**	$ —	Liabilities from risk management activities	**$ —**	$ —
Total		**$ 1**	$ —		**$ 100**	$ 72

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2015 and 2014 .

The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. At December 31, 2015 and 2014 , energy-related derivatives and interest rate derivatives presented in the tables above do not have amounts available for offset.

At December 31, 2015 and 2014 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (49)**	$ (37)	Other regulatory liabilities, current	**$ —**	$ —
	Other regulatory assets, deferred	**(51)**	(35)	Other regulatory liabilities, deferred	**—**	—
Total energy-related derivative gains (losses)		**$ (100)**	$ (72)		**$ —**	$ —

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2015**	2014	2013	**Statements of Income Location**	**2015**	2014	2013
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ 1**	$ —	$ —	Interest expense, net of amounts capitalized	**$ (1)**	$ (1)	$ (1)

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

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2015 , the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2015 , the fair value of derivative liabilities with contingent features was $22 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $52 million and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. 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 2015 and 2014 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in millions)	
March 2015	**$ 357**	**$ 72**	**$ 37**
June 2015	**384**	**69**	**35**
September 2015	**429**	**91**	**48**
December 2015	**313**	**58**	**28**
March 2014	$ 407	$ 74	$ 37
June 2014	384	69	34
September 2014	438	88	46
December 2014	361	50	23

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

SELECTED FINANCIAL AND OPERATING DATA 2011 - 2015
Gulf Power Company 2015 Annual Report

	2015	2014	2013	2012	2011
Operating Revenues (in millions)	**$ 1,483**	$ 1,590	$ 1,440	$ 1,440	$ 1,520
Net Income After Dividends on Preference Stock (in millions)	**$ 148**	$ 140	$ 124	$ 126	$ 105
Cash Dividends on Common Stock (in millions)	**$ 130**	$ 123	$ 115	$ 116	$ 110
Return on Average Common Equity (percent)	**11.11**	11.02	10.30	10.92	9.55
Total Assets (in millions) [(a)(b)]	**$ 4,920**	$ 4,697	$ 4,321	$ 4,167	$ 3,858
Gross Property Additions (in millions)	**$ 247**	$ 361	$ 305	$ 325	$ 338
Capitalization (in millions):					
Common stock equity	**$ 1,355**	$ 1,309	$ 1,235	$ 1,181	$ 1,125
Preference stock	**147**	147	147	98	98
Long-term debt [(a)]	**1,193**	1,362	1,150	1,178	1,226
Total (excluding amounts due within one year)	**$ 2,695**	$ 2,818	$ 2,532	$ 2,457	$ 2,449
Capitalization Ratios (percent):					
Common stock equity	**50.3**	46.5	48.8	48.1	45.9
Preference stock	**5.4**	5.2	5.8	4.0	4.0
Long-term debt [(a)]	**44.3**	48.3	45.4	47.9	50.1
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**393,149**	388,292	383,980	379,922	378,248
Commercial	**55,460**	54,892	54,567	53,808	53,450
Industrial	**248**	260	260	264	273
Other	**614**	603	582	577	565
Total	**449,471**	444,047	439,389	434,571	432,536
Employees (year-end)	**1,391**	1,384	1,410	1,416	1,424

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $8 million, $8 million, $8 million, and $9 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-03. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(b) A reclassification of deferred tax assets from Total Assets of $3 million, $8 million, $2 million, and $5 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-17. See Note 1 under "Recently Issued Accounting Standards" for additional information.

SELECTED FINANCIAL AND OPERATING DATA 2011 - 2015 (continued)
Gulf Power Company 2015 Annual Report

	2015	2014	2013	2012	2011
Operating Revenues (in millions):					
Residential	$ 698	$ 700	$ 632	$ 609	$ 637
Commercial	403	408	395	390	408
Industrial	144	153	139	140	158
Other	4	6	4	5	5
Total retail	1,249	1,267	1,170	1,144	1,208
Wholesale — non-affiliates	107	129	109	107	134
Wholesale — affiliates	58	130	100	124	111
Total revenues from sales of electricity	1,414	1,526	1,379	1,375	1,453
Other revenues	69	64	61	65	67
Total	$ 1,483	$ 1,590	$ 1,440	$ 1,440	$ 1,520
Kilowatt-Hour Sales (in millions):					
Residential	5,365	5,362	5,089	5,054	5,305
Commercial	3,898	3,838	3,810	3,859	3,911
Industrial	1,798	1,849	1,700	1,725	1,799
Other	25	26	21	25	25
Total retail	11,086	11,075	10,620	10,663	11,040
Wholesale — non-affiliates	1,040	1,670	1,163	977	2,013
Wholesale — affiliates	1,906	3,284	3,127	4,370	2,608
Total	14,032	16,029	14,910	16,010	15,661
Average Revenue Per Kilowatt-Hour (cents):					
Residential	13.01	13.06	12.43	12.06	12.01
Commercial	10.34	10.64	10.37	10.11	10.44
Industrial	8.01	8.28	8.15	8.14	8.80
Total retail	11.27	11.44	11.02	10.73	10.95
Wholesale	5.60	5.23	4.87	4.31	5.30
Total sales	10.08	9.52	9.25	8.59	9.28
Residential Average Annual					
Kilowatt-Hour Use Per Customer	13,705	13,865	13,301	13,303	14,028
Residential Average Annual					
Revenue Per Customer	$ 1,783	$ 1,811	$ 1,653	$ 1,604	$ 1,685
Plant Nameplate Capacity					
Ratings (year-end) (megawatts)	2,583	2,663	2,663	2,663	2,663
Maximum Peak-Hour Demand (megawatts):					
Winter	2,488	2,684	1,729	2,130	2,485
Summer	2,491	2,424	2,356	2,344	2,527
Annual Load Factor (percent)	54.9	51.1	55.9	56.3	54.5
Plant Availability Fossil-Steam (percent) *	88.3	89.4	92.8	82.5	84.7
Source of Energy Supply (percent):					
Coal	33.5	44.5	36.4	34.6	49.4
Gas	25.6	22.2	23.0	23.5	24.0
Purchased power —					
From non-affiliates	30.4	28.9	37.0	40.2	22.3
From affiliates	10.5	4.4	3.6	1.7	4.3
Total	100.0	100.0	100.0	100.0	100.0

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

MISSISSIPPI POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2015 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, 2015 .

/s/ Anthony L. Wilson
Anthony L. Wilson
President and Chief Executive Officer

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

February 26, 2016

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, 2015 and 2014 , 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, 2015 . 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 II-399 to II-445) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2015 and 2014 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015 , in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 26, 2016

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
APA	Asset purchase agreement
ASC	Accounting Standards Codification
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
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 account for use in mitigating future rate impacts for customers
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 operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
scrubber	Flue gas desulfurization system

DEFINITIONS
(continued)

Term	Meaning
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
SRR	System Restoration Rider
traditional 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 2015 Annual Report

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain 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 major construction projects, primarily the Kemper IGCC and the Plant Daniel scrubber project, projected long-term demand growth, reliability, fuel, and increasingly stringent environmental standards, as well as ongoing capital expenditures required for maintenance. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC established by the Mississippi PSC was $2.4 billion with a construction cost cap of $2.88 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the 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 Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC in-service in August 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities. The in-service date for the remainder of the Kemper IGCC is currently expected to occur in the third quarter 2016.

The Company's current cost estimate for the Kemper IGCC in total is approximately $6.63 billion , which includes approximately $5.29 billion of costs subject to the construction cost cap. 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 DOE Grants and excluding the Cost Cap Exceptions. The Company has recorded pre-tax charges to income for revisions to the cost estimate of $365 million ($226 million after tax), $868 million ($536 million after tax), and $1.1 billion ($681 million after tax) in 2015 , 2014 , and 2013 , respectively. Since 2012, in the aggregate, the Company has incurred charges of $ 2.41 billion ($1.5 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2015 . The current cost estimate includes costs through August 31, 2016.

During 2015, events related to the Kemper IGCC had a significant adverse impact on the Company’s financial condition. These events include (i) the termination by SMEPA in May 2015 of the APA between the Company and SMEPA, whereby SMEPA previously agreed to purchase a 15% undivided interest in the Kemper IGCC, and the Company's subsequent return of approximately $301 million , including interest, to SMEPA; (ii) the termination of Mirror CWIP rates in July 2015 and the refund of $371 million in Mirror CWIP rate collections, including carrying costs, in the fourth quarter 2015 as a result of the Mississippi Supreme Court's (Court) reversal of the Mississippi PSC's 2013 rate order authorizing the collection of $156 million annually in Mirror CWIP rates; and (iii) the required recapture in December 2015 of $235 million of Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 48A (Phase II) tax credits as a result of the extension of the expected in-service date for the Kemper IGCC. As a result of the termination of the Mirror CWIP rates, the Company submitted a filing to the Mississippi PSC requesting interim rates to collect approximately $159 million annually until a final rate decision could be made on the Company's request to recover costs associated with Kemper IGCC assets that had been placed in service. The Mississippi PSC approved the implementation of the requested interim rates in August 2015. Subsequently, on December 3, 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), based on a stipulation (the 2015 Stipulation) between the Company and the MPUS, authorizing the Company to replace the interim rates with rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service. Further proceedings related to cost recovery for the Kemper IGCC are expected after the remainder of the Kemper IGCC is placed in service which is currently expected in the third quarter 2016. On February 25, 2016, Greenleaf CO2 Solutions, LLC filed a notice of appeal of the In-Service Asset Rate Order with the Court. The Company believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on the Company’s results of operations, financial condition, and liquidity. The ultimate outcome of this matter cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information.

As of December 31, 2015 , the Company's current liabilities exceeded current assets by approximately $1.3 billion primarily due to $900 million of bank term loans scheduled to mature on April 1, 2016, and $300 million in senior notes scheduled to mature on October 15, 2016. See FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" herein and Note 6 to the financial statements for additional information. The Company expects to refinance its 2016 debt maturities with bank term loans. The Company intends to utilize operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company to fund the remainder of the Company's capital needs.

Key Performance Indicators

The Company continues to focus on several key performance indicators, including the construction and start-up of the Kemper IGCC, to measure the Company's performance for customers and employees.

In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the Company's allowed return. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in percentage of time customers had electric service (40%); and customer satisfaction, measured in a survey of residential customers (20%). See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

In addition to the PEP performance indicators, the Company focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock.

The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile in measuring performance, which the Company achieved during 2015.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's 2015 fossil Peak Season EFOR of 0.76% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's 2015 performance was better than the target for these transmission and distribution reliability measures.

The Company uses net income (loss) after dividends on preferred stock as the primary measure of the Company's financial 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 $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 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 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 SMEPA's agreement to purchase a portion of the Kemper IGCC, 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.

The Company's net loss after dividends on preferred stock was $329 million in 2014 compared to $477 million in 2013 . The decreased net loss in 2014 was primarily the result of lower pre-tax charges of $868 million ($536 million after tax) in 2014 compared to pre-tax charges of $1.1 billion ($681 million after tax) in 2013 for revisions of estimated costs expected to be incurred on the Company’s construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions. The change was also due to wholesale base rate increases, effective in April 2013 and May 2014, and an increase in AFUDC equity primarily related to the construction of the Kemper IGCC. These changes were partially offset by a decrease in retail revenues primarily as a result of the 2015 Court decision which required the reversal of revenues recorded in 2013, increases in non-fuel operations and maintenance expenses and interest expense. 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	
	2015	2015	2014
		(in millions)	
Operating revenues	$ 1,138	$ (105)	$ 98
Fuel	443	(131)	83
Purchased power	12	(31)	(6)
Other operations and maintenance	274	3	18
Depreciation and amortization	123	26	6
Taxes other than income taxes	94	15	(2)
Estimated loss on Kemper IGCC	365	(503)	(234)
Total operating expenses	1,311	(621)	(135)
Operating income	(173)	516	233
Allowance for equity funds used during construction	110	(26)	14
Interest expense, net of amounts capitalized	7	(38)	9
Other income (expense), net	(8)	6	(7)
Income taxes (benefit)	(72)	213	83
Net income (loss)	(6)	321	148
Dividends on preferred stock	2	—	—
Net income (loss) after dividends on preferred stock	$ (8)	$ 321	$ 148

Operating Revenues

Operating revenues for 2015 were $1.1 billion , reflecting a $105 million decrease from 2014 . Details of operating revenues were as follows:

	Amount	
	2015	2014
	(in millions)	
Retail — prior year	$ 795	$ 799
Estimated change resulting from —		
Rates and pricing	61	(12)
Sales growth (decline)	(3)	(1)
Weather	(1)	3
Fuel and other cost recovery	(76)	6
Retail — current year	776	795
Wholesale revenues —		
Non-affiliates	270	323
Affiliates	76	107
Total wholesale revenues	346	430
Other operating revenues	16	18
Total operating revenues	$ 1,138	$ 1,243
Percent change	(8.4)%	8.5%

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. Total retail revenues for 2014 decreased $5 million, or

0.6%, compared to 2013 primarily as a result of $10 million in revenues recorded in 2013 that were reversed in 2014 as a result of the 2015 Court decision.

Revenues associated with changes in rates and pricing increased in 2015 when compared to 2014, primarily due to $50 million of net revenues associated with the implementation of rates for the Kemper IGCC that began in August 2015. In addition, 2014 revenues included the reversal of $11 million for 2013 as a result of the 2015 Court decision.

See Note 3 to the financial statements under "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:

	2015	2014	2013
		(in millions)	
Capacity and other	**$ 158**	$ 160	$ 143
Energy	**112**	163	151
Total non-affiliated	**$ 270**	$ 323	$ 294

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. The Company serves long-term contracts with rural electric 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 21.0% of the Company’s total operating revenues in 2015 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 $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. Wholesale revenues from sales to non-affiliates increased $29 million, or 9.8%, in 2014 compared to 2013 as a result of a $17 million increase in base revenues primarily resulting from wholesale base rate increases effective April 1, 2013 and May 1, 2014 and a $12 million increase in energy revenues, of which $10 million was associated with an increase in KWH sales and $2 million was associated with higher 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 $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 prices and $3 million was associated with a decrease in KWH sales. Wholesale revenues from sales to affiliates increased $72 million, or 208.3%, in 2014 compared to 2013 primarily due to a $75 million increase in energy revenues of which $69 million was associated with an increase in KWH sales and $5 million was associated with higher prices, partially offset by a decrease in capacity revenues of $2 million.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2015 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2015	**2015**	2014	**2015***	2014
	(in millions)				
Residential	**2,025**	**(4.8)%**	1.8 %	**(0.4)%**	(2.3)%
Commercial	**2,806**	**(1.9)**	(0.2)	**(0.4)**	0.1
Industrial	**4,958**	**0.3**	4.3	**0.8**	4.3
Other	**40**	**(2.1)**	1.1	**(2.1)**	1.1
Total retail	**9,829**	**(1.4)**	2.4	**0.2 %**	1.6 %
Wholesale					
Non-affiliated	**3,852**	**(8.1)**	6.7		
Affiliated	**2,807**	**(3.2)**	211.4		
Total wholesale	**6,659**	**(6.1)**	45.9		
Total energy sales	**16,488**	**(3.4)%**	16.9 %		

* 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 significant 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 KWH sales among customer classes that is consistent with the actual allocation 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 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.

Retail energy sales increased 2.4% in 2014 as compared to the prior year. This increase was primarily the result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and customer growth, partially offset by a decrease in customer usage. The increase in industrial KWH energy sales was primarily due to increased production related to expanded operation by many industrial customers. Weather-adjusted residential KWH energy sales decreased 2.3% in 2014 compared to 2013 due to lower average usage per customer. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

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 system prices. Wholesale energy sales to non-affiliates increased in 2014 compared to 2013 primarily due to increased opportunity sales to the external market as a result of lower system prices.

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

Wholesale energy sales to affiliates decreased in 2015 compared to 2014 primarily due to lower fuel cost and less sales to affiliate companies. Wholesale energy sales to affiliates increased in 2014 compared to 2013 primarily due to an increase in the Company's generation, resulting in more energy available to sell to affiliate companies.

Fuel and Purchased Power Expenses

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

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

	2015	2014	2013
Total generation *(millions of KWHs)*	**17,014**	16,881	13,721
Total purchased power *(millions of KWHs)*	**539**	886	1,559
Sources of generation *(percent)* –			
Coal	**17**	42	36
Gas	**83**	58	64
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.71**	3.96	4.97
Gas	**2.58**	3.37	3.16
Average cost of fuel, generated *(cents per net KWH)*	**2.78**	3.64	3.87
Average cost of purchased power *(cents per net KWH)*	**2.17**	4.85	3.10

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 KWHs generated by coal generation and purchased power, partially offset by a $146 million increase in KWHs generated by gas generation. Fuel and purchased power expenses were $617 million in 2014, an increase of $77 million, or 14.3%, as compared to the prior year. The increase was primarily due to a $114 million increase in the total volume of KWHs generated, offset by a $37 million decrease in the cost of fuel and purchased power.

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 $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 KWH generated in 2015. Fuel expense increased $83 million, or 16.8%, in 2014 compared to 2013. The increase was the result of a 24.5% increase in the volume of KWHs generated in 2014, partially offset by a 5.9% decrease in the average cost of fuel per KWH generated.

Purchased Power - Non-Affiliates

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. Purchased power expense from non-affiliates increased $12 million, or 210.3%, in 2014 compared to 2013. The increase was primarily the result of a 276.7% increase in the average cost per KWH purchased, partially offset by a 17.6% decrease in the volume of KWHs purchased. The increase in the average cost per KWH purchased was due to a higher marginal cost of fuel.

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

Purchased Power - Affiliates

Purchased power expense from affiliates decreased $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. Purchased power expense from affiliates decreased $18 million, or 41.1%, in 2014 compared to 2013. The decrease in 2014 was primarily the result of a 49.5% decrease in the volume of KWHs purchased, offset by a 16.8% increase in the average cost per KWH purchased compared to 2013.

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 $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 interim 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.

Other operations and maintenance expenses increased $18 million, or 6.8%, in 2014 compared to 2013 primarily due to a $14 million increase in employee compensation and benefit expenses and a $7 million increase in generation maintenance expenses. These increases in 2014 were partially offset by a $2 million decrease in transmission expenses primarily related to overhead line maintenance and vegetation management, and a $1 million decrease in customer accounting expenses primarily due to uncollectibles.

Depreciation and Amortization

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 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.

Depreciation and amortization increased $6 million, or 6.3%, in 2014 compared to 2013 primarily due to a $4 million increase related to the reversal of a regulatory deferral associated with the Kemper IGCC municipal franchise taxes, a $2 million increase in depreciation related to an increase in assets in service, and a $2 million increase resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4. These increases were partially offset by a $4 million decrease associated with a wholesale revenue requirement adjustment.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "FERC Matters" and " – Environmental Compliance Overview Plan" for additional information.

Taxes Other Than Income Taxes

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. Taxes other than income taxes decreased $2 million, or 2.0%, in 2014 compared to 2013 primarily as a result of a $6 million decrease in franchise taxes, partially offset by a $3 million increase in ad valorem taxes and a $1 million increase 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 $365 million and $868 million were recorded in 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 DOE Grants and excluding the Cost Cap Exceptions.

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

Allowance for Equity Funds Used During Construction

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. AFUDC equity increased $14 million, or 12.2%, in

2014 as compared to 2013. The increase in 2014 was primarily due to CWIP related to the Company's Kemper IGCC. 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 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 agreement for SMEPA to purchase a portion of the Kemper IGCC 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.

Interest expense, net of amounts capitalized increased $9 million, or 24.2%, in 2014 compared to 2013, primarily due to an $11 million increase in interest expense resulting from the receipt of $125 million interest-bearing refundable deposits from SMEPA, an $8 million increase in interest expense on the regulatory liability related to the Kemper IGCC rate recovery, a $5 million increase in interest expense primarily associated with the issuances of long-term debt in 2014, and a $3 million increase in other interest expense. These increases in 2014 over the prior year were partially offset by a $15 million increase in capitalized interest resulting from carrying costs associated with the Kemper IGCC and a $3 million decrease in interest expense primarily associated with the redemption of long-term debt in late 2013.

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.

Other Income (Expense), Net

Other income (expense), net increased $6 million , or 42.9% , in 2015 compared to 2014 primarily due to $7 million associated with a settlement with the Sierra Club in 2014, partially offset by a $1 million increase in donations. Other income (expense), net decreased $7 million, or 133.7%, in 2014 compared to 2013 primarily due to $7 million associated with a settlement with the Sierra Club and a $1 million increase in consulting fees.

Income Taxes (Benefit)

Income taxes (benefit) increased $213 million , or 74.7% , in 2015 compared to 2014 and increased $83 million, or 22.5%, in 2014 compared to 2013 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 electricity to retail customers within its traditional service area located in southeast Mississippi and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. See "FERC Matters" herein, ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein, and Note 3 to the financial statements 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 prevail against legal challenges associated with the Kemper IGCC, recover its prudently-incurred costs in a timely manner during a time of increasing costs and the completion and subsequent operation of the Kemper IGCC in accordance with any operational parameters that may be adopted by the Mississippi

PSC, as well as other ongoing construction projects. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of 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 partially 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.

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 market-based contracts. 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 2015 , the Company had invested approximately $617 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $94 million, $118 million, and $104 million for 2015 , 2014 , and 2013 , respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $66 million from 2016 through 2018 , with annual totals of approximately $21 million, $19 million, and $26 million for 2016 , 2017 , and 2018 , respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with closure in place and ground water monitoring of ash ponds in accordance with the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation (ARO) liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, 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. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. The compliance deadline set by the final MATS rule was April 16, 2015, with provisions for extensions to April 16, 2016. The implementation strategy for the MATS rule includes emission controls, retirements, and fuel conversions to achieve compliance by the deadlines applicable to each Company unit. On June 29, 2015, the U.S. Supreme Court issued a decision finding that in developing the MATS rule the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units. On December 15, 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule to the EPA without vacatur to respond to the U.S. Supreme Court's decision. The EPA's supplemental finding in response to the U.S. Supreme Court's decision, which the EPA proposes to finalize in April 2016, is not expected to have any impact on the MATS rule compliance requirements and deadlines.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). On October 26, 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 will recommend area designations by October 2016, and the EPA is expected to finalize them by October 2017.

Final revisions to the NAAQS for sulfur dioxide (SO_2) , which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has finalized a data requirements rule to support additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

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

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I having begun in 2015 and Phase II beginning in 2017. On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Alabama, but rejected all other pending challenges to the rule. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. On December 3, 2015, the EPA published a proposed revision to CSAPR that would revise existing ozone-season emissions budgets for nitrogen oxide in Alabama and Mississippi. The EPA proposes to finalize this rulemaking by summer 2016.

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.

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

On June 12, 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) by no later than November 22, 2016.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. The impacts of the eight-hour ozone and SO_2 NAAQS, the Alabama opacity rule, CSAPR, regional haze regulations, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. 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.

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 October 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

On November 3, 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 National Pollutant Discharge Elimination System 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. The ultimate impact of these requirements will depend on pending and any future legal challenges, compliance dates, and implementation of the final rule and cannot be determined at this time.

On June 29, 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 August 28, 2015, but on October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The ultimate impact of the final rule will depend on the outcome of this and other pending legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

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.

On April 17, 2015, the EPA published the CCR Rule in the Federal Register, which became effective on October 19, 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. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

Based on initial cost estimates for closure in place and groundwater monitoring of ash ponds pursuant to the CCR Rule, the Company 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, 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. The Company is currently completing an analysis of the plan of closure for all ash ponds, including the timing of closure and related cost recovery through regulated rates subject to Mississippi PSC approval. Based on the results of that analysis, the Company may accelerate the timing of some ash pond closures which could increase its ARO liabilities from the amounts presently recorded. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. 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, 2015.

Environmental Remediation

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

Global Climate Issues

On October 23, 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 its review with the courts. The stay will remain in effect through the resolution of the litigation, whether resolved in the U.S. Court of Appeals for the District of Columbia Circuit or 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. 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 Company's ongoing review of the final rules; the outcome of legal challenges, including legal challenges filed by the traditional operating companies; individual state implementation of the EPA's final guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

The United Nations 21st international climate change conference took place in late 2015. The result was the adoption of 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 increasing those commitments every five years. The ultimate impact of this agreement depends on its ratification and implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2014 greenhouse gas emissions were approximately 11 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2015 greenhouse gas emissions on the same basis is approximately 9 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 March 2014, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an increase in the MRA cost-based electric tariff. The settlement agreement, accepted by the FERC in May 2014, provided that base rates under the MRA cost-based electric tariff increased approximately $10 million annually, effective May 1, 2014.

Included in this settlement agreement, an adjustment to the Company's wholesale revenue requirement in a subsequent rate proceeding was allowed 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.

On May 13, 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. The additional resulting AFUDC is estimated to be approximately $14 million annually, of which $11 million relates to the Kemper IGCC.

See Note 3 to the financial statements under "FERC Matters" for more information.

Fuel Cost Recovery

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2016, the wholesale MRA fuel rate decreased $47 million annually. Effective February 1, 2016, the wholesale MB fuel rate decreased $2 million annually. At December 31, 2015, the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $ 24 million compared to an immaterial balance at December 31, 2014.

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.

See Note 3 to the financial statements under "FERC Matters" for more information.

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 operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional 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 operating companies and in some adjacent areas. The FERC directed the traditional 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 operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

General

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the 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 the Kemper IGCC, 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

On November 10, 2015, the Mississippi PSC issued three separate 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 of the contracts under three PPAs, two of which have been finalized and one of which remains under negotiation. The projects are expected to be in service by the end of 2016 and the resulting energy purchases will be recovered through the Company's fuel cost recovery mechanism.

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.

In June 2014, the Mississippi PSC approved the Company's 2014 Energy Efficiency Quick Start Plan filing, which includes a portfolio of energy efficiency programs. In November 2014, the Mississippi PSC approved the Company's revised compliance filing, which proposed an increase of $7 million in retail revenues for the period December 2014 through December 2015. On December 4, 2015, the Company submitted its annual Energy Efficiency Cost Rider Compliance filing, which included a reduction of $2 million in retail revenues for the year ending December 31, 2016. The ultimate outcome of this matter cannot be determined at this time.

Performance Evaluation Plan

The Company’s retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on projected revenue requirement, and the PEP lookback filing, which is filed after the year and allows for review of 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. I n 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 certain costs included in the 2010 PEP lookback filing, which are currently 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 March 2014 and 2015, the Company submitted its annual PEP lookback filings for 2013 and 2014, respectively, which each indicated no surcharge or refund. The Mississippi PSC suspended each of the filings to allow more time for review.

In June 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.

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 August 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 August 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. 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 on April 16, 2015), and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016.

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. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. As of December 31, 2015, $5 million of Plant Greene County costs and $36 million of costs related to Plant Watson have been reclassified as regulatory assets. These costs are expected to be recovered through the ECO plan and other existing cost recovery mechanisms. Additional costs associated with the remaining net book value of coal-related equipment will be reclassified to a regulatory asset at the time of retirement for Plants Watson and Greene County in 2016. Approved regulatory asset costs will be amortized over a period to be determined by the Mississippi PSC. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

On December 3, 2015, the Mississippi PSC approved the Company's revised ECO filing for 2015, which indicated no change in revenue.

On February 12, 2016, the Company submitted its ECO filing for 2016, which requested an increase in annual revenues, capped at 2% of total retail revenues, of approximately $18 million, primarily related to the scrubbers on Plant Daniel Units 1 and 2. The revenue requirement in excess of the 2%, approximately $26 million, will be carried forward to the 2017 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 21, 2016, which will result in an annual revenue decrease of approximately $120 million . At December 31, 2015, the amount of over-recovered retail fuel costs included in the balance sheets was $71 million compared to a $3 million under-recovered balance at December 31, 2014.

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.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of the Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation 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 planned 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 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 using natural gas in August 2014 and currently expects to place the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, in service during the third quarter 2016.

Recovery of the costs subject to the cost cap and the Cost Cap Exceptions remains subject to review and approval by the Mississippi PSC. The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Court's decision), and actual costs incurred as of December 31, 2015, are as follows:

Cost Category	2010 Project Estimate [f]	Current Cost Estimate [a]	**Actual Costs**
		(in billions)	
Plant Subject to Cost Cap [b][g]	$ 2.40	$ 5.29	**$ 4.83**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC [c]	0.17	0.69	**0.59**
Combined Cycle and Related Assets Placed in Service – Incremental [d][g]	—	0.01	**0.01**
General Exceptions	0.05	0.10	**0.09**
Deferred Costs [e][g]	—	0.20	**0.17**
Total Kemper IGCC	$ 2.97	$ 6.63	**$ 6.03**

(a) Amounts in the Current Cost Estimate reflect estimated costs through August 31, 2016.

(b) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , net of the DOE Grants and excluding the Cost Cap Exceptions. 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. The Current Cost Estimate and the Actual Costs reflect 100% of the costs of the Kemper IGCC. See note (g) for additional information.

(c) The Company's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs." The current estimate 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.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information.

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

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

(g) Beginning in the third quarter 2015, certain costs, including debt carrying costs (associated with assets placed in service and other non-CWIP accounts), that previously were deferred as regulatory assets are now being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2015.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2015 , $3.47 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.41 billion), $2 million in other property and investments, $69 million in fossil fuel stock, $45 million in materials and supplies, $21 million in other regulatory assets, current, $195 million in other regulatory assets, deferred, and $11 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 DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate above the cost cap of $365 million ($226 million after tax), $868 million ($536 million after tax), and $1.1 billion ($681 million after tax) in 2015, 2014, and 2013, respectively. The increases to the cost estimate in 2015 primarily reflect costs for the extension of the Kemper IGCC's projected in-service date through August 31, 2016, increased efforts related to scope modifications, additional labor costs in support of start-up and operational readiness activities, and system repairs and modifications after startup testing and commissioning activities identified necessary remediation of equipment installation, fabrication, and design issues, including the refractory lining inside the gasifiers; the lignite feed and dryer systems; and the syngas cooler vessels. Any extension of the in-service date beyond August 31, 2016 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 August 31, 2016 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 $13 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 $2 million per month. For additional information, see "2015 Rate Case" herein.

The Company's analysis of the time needed to complete the start-up and commissioning activities for the Kemper IGCC will continue until the remaining Kemper IGCC assets are placed in service. Further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, 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 for this first-of-a-kind technology (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). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of operations and these changes could be material.

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" herein for additional information regarding the Company's MRA cost-based tariff relating to recovery of a portion of the Kemper IGCC costs from the Company's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See "Income Tax Matters" herein for additional tax information related to the Kemper IGCC.

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

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN. The Company expects the Mississippi PSC to apply operational parameters in connection with 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.

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.

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. The Company will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts.

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order. 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 below.

2015 Rate Case

As a result of the 2015 Court decision, on July 10, 2015, the Company filed a request for interim rates (Supplemental Notice) with the Mississippi PSC which presented an alternative rate proposal (In-Service Asset Proposal) for consideration by the Mississippi PSC. The In-Service Asset Proposal was based upon the test period of June 2015 to May 2016, was 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, and was designed to collect approximately $159 million annually. On August 13, 2015, the Mississippi PSC approved the implementation of interim rates that became effective with the first billing cycle in September, 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. Consistent with the 2015 Stipulation, the In-Service Asset Rate Order provides 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 during the test period. The In-Service Asset Rate Order also includes a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excludes the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA . See "Termination of Proposed Sale of Undivided Interest to SMEPA" herein for additional information.

With implementation of the new rate on December 17, 2015, the interim rates were terminated and the Company recorded a customer refund of approximately $11 million in December 2015 for the difference between the interim rates collected and the permanent rates. The refund is required to be completed by March 16, 2016.

Pursuant to the In-Service Asset Rate Order, the Company is required to file a subsequent rate request within 18 months . As part of the filing, the Company expects to request recovery of certain costs that the Mississippi PSC had excluded from the revenue requirement calculation.

On February 25, 2016, Greenleaf CO2 Solutions, LLC filed a notice of appeal of the In-Service Asset Rate Order with the Court. The Company believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on the Company's results of operations, financial condition, and liquidity. The ultimate outcome of this matter cannot be determined at this time.

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 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.

The Company expects to seek additional rate relief to address recovery of the remaining Kemper IGCC assets. In addition to current estimated costs at December 31, 2015 of $ 6.63 billion , the Company anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

The Company expects the Kemper IGCC to qualify for additional DOE grants included in the recently passed Consolidated Appropriations Act of 2015, which are expected to be used to reduce future rate impacts for customers. The ultimate outcome of this matter cannot be determined at this time.

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, in connection with the implementation of interim rates, the Company began expensing certain ongoing project costs and certain 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. As of December 31, 2015, the balance associated with these regulatory assets was $120 million . Other regulatory assets associated with the remainder of the Kemper IGCC totaled $96 million as of December 31, 2015 . The amortization period for these assets is expected to be determined by the Mississippi PSC in future rate proceedings following completion of construction and start-up of the Kemper IGCC and related prudence reviews.

See "2013 MPSC Rate Order" herein for information related to the July 7, 2015 Mississippi PSC order terminating the Mirror CWIP rate and requiring refund of collections under Mirror CWIP.

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. As of December 31, 2015, the Company recorded a related regulatory liability of approximately $2 million . See "2015 Rate Case" herein for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation 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 has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide Denbury and Treetop with termination rights as the Company has not satisfied its contractual obligation to deliver captured CO_2 by May 11, 2015. Since May 11, 2015, the Company has been engaged in ongoing discussions with its off-takers regarding the status of the CO_2 delivery schedule as well as other issues related to the CO_2 agreements. As a result of discussions with Treetop, on August 3, 2015, the Company agreed to amend certain provisions of their agreement that do not affect pricing or minimum purchase quantities. Potential requirements imposed on CO_2 off-takers under the Clean Power Plan (if ultimately enacted in its current form, pending resolution of litigation) and the potential adverse financial impact of low oil prices on the off-takers increase the risk that the CO_2 contracts may be terminated or materially modified. Any termination or material modification of these agreements could 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. Additionally, if the contracts remain in place, sustained oil price reductions could result in significantly lower revenues than the Company forecasted to be available to offset customer rate impacts, which could have a material impact on the Company's financial statements. See "Environmental Matters – Global Climate Issues" herein for additional information regarding the Clean Power Plan and related litigation.

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

Termination of Proposed Sale of Undivided Interest to SMEPA

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. On May 20, 2015, SMEPA notified the Company that it was terminating the agreement. The Company had previously received a total of $275 million of deposits from SMEPA that were returned by Southern Company to SMEPA, with interest of approximately $26 million , on June 3, 2015, as a result of the termination, pursuant to its guarantee obligation. Subsequently, the Company issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures December 1, 2017.

The In-Service Asset Proposal and the related rates approved by the Mississippi PSC excluded any costs associated with the 15% undivided interest. The Company continues to evaluate its alternatives with respect to its investment and the related costs associated with the 15% undivided interest.

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

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years . The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 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 50% bonus depreciation is expected to result in approximately $85 million of positive cash flows for the 2015 tax year and approximately $390 million for the 2016 tax year, which may not all be realized in 2016 due to a projected net operating loss in the Company's 2016 tax return. Approximately $360 million of the 2016 benefit is dependent upon placing the remainder of the Kemper IGCC in service in 2016. The ultimate outcome of this matter cannot be determined at this time.

Investment Tax Credits

The IRS allocated $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 April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. As a result of the schedule extension for the Kemper IGCC, the Phase II tax credits have been recaptured.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations for 2013, 2014, and 2015. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures. Due to the uncertainty related to this tax position, the Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $423 million as of December 31, 2015 . See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. Also see "Bonus Depreciation" herein. 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 February 2013, the Company submitted a claim under the Deepwater Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in April 2010 in the Gulf of Mexico. The ultimate outcome of this matter cannot be determined at this time.

On April 16, 2015, the majority of assets that supported coal generation at Plant Watson Units 4 and 5 were retired. The remaining net book value of these two units was approximately $32 million, excluding the reserve for cost of removal, and has been reclassified to other regulatory assets, deferred, in accordance with an accounting order from the Mississippi PSC. The Company expects to recover through its rates the remaining book value of the retired assets and certain costs, including unusable inventory, associated with the retirements; however, the ultimate method and timing of recovery will be considered by the Mississippi PSC in future rate proceedings.

The Company expects the Kemper IGCC to qualify for additional DOE grants included in the recently passed Consolidated Appropriations Act of 2015, which are expected to be used to reduce future rate impacts for customers. The ultimate outcome of this matter cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

The Company is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

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

During 2015 , 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 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 DOE Grants and excluding the Cost Cap Exceptions.

As a result of the revisions to the cost estimate, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $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 $2.4 billion ($1.5 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2015 .

The Company has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the statements of operations and these changes could be material. Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, 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 for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including, but not limited to, additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

The Company's revised cost estimate includes costs through August 31, 2016. Any extension of the in-service date beyond August 31, 2016 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 August 31, 2016 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 $13 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 $2 million per month.

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.

As a result of the final CCR Rule discussed above, the Company recorded new AROs for facilities that are subject to the CCR Rule. The cost estimates 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 in place. 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, 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.

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 has 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 will decrease 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 $1 million or less change in total annual benefit expense and a $20 million or less change in projected obligations.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 5.99% , 6.91% , and 6.89% for the years ended December 31, 2015 , 2014 , and 2013 , respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC equity was $110 million , $136 million, and $122 million, in 2015, 2014, and 2013, 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

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers* , revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $9 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 9 to the financial statements for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07) *,* effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the Company. See Note 2 to the financial statements for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid income taxes of $121 million with $105 million to non-current accumulated deferred income taxes and $16 million to other deferred charges in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 to the financial statements for disclosures impacted by ASU 2015-17.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition and its ability to obtain financing needed for normal business operations and completion of construction and start-up of the Kemper IGCC were adversely affected by the return of approximately $301 million of interest bearing refundable deposits to SMEPA in June 2015 in connection with the termination of the APA, the required refund of the approximately $371 million of Mirror CWIP rate collections, including associated carrying costs, the termination of the Mirror CWIP rate, and the required recapture of Phase II tax credits. Earnings for the twelve months ended December 31, 2015 were negatively affected by revisions to the cost estimate for the Kemper IGCC and the Court's decision to reverse the 2013 MPSC Rate Order. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA," –"Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order," "– 2015 Rate Case," and – "Income Tax Matters – Investment Tax Credits" herein for additional information.

Through December 31, 2015 , the Company has incurred non-recoverable cash expenditures of $1.95 billion and is expected to incur approximately $0.46 billion in additional non-recoverable cash expenditures through completion of the construction and start-up of the Kemper IGCC.

In addition to funding normal business operations and projected capital expenditures, the Company's near-term cash requirements primarily consist of $900 million of bank term loans scheduled to mature on April 1, 2016, $300 million in senior notes scheduled to mature on October 15, 2016, $25 million of short-term debt, and the required refund of approximately $11 million in customer refunds associated with the In-Service Asset Rate Order. For the three-year period from 2016 through 2018, the Company's capital expenditures and debt maturities are expected to materially exceed operating cash flows. In addition to the Kemper IGCC, projected capital expenditures in that period include investments to maintain existing generation facilities, to add environmental modifications to existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. The Company expects to refinance its 2016 debt maturities with bank term loans. The Company intends to utilize operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company to fund the remainder of the Company's capital needs. See "Capital Requirements and Contractual Obligations," "Sources of Capital," and "Financing Activities herein for additional information.

The Company's investments in the qualified pension plan remained stable in value as of December 31, 2015 as compared to December 31, 2014. No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated during 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 provided from operating activities totaled $735 million for 2014, an increase of $287 million as compared to the corresponding period in 2013. The increase in net cash provided from operating activities was primarily due to deferred income taxes and Mirror CWIP rate collections, net of the Kemper IGCC regulatory deferral, partially offset by a decrease in ITCs received related to the Kemper IGCC, an increase in prepaid income taxes, increases in fossil fuel stock, and an increase in regulatory assets associated with the Kemper IGCC.

Net cash used for investing activities in 2015, 2014, and 2013 totaled $0.9 billion, $1.3 billion, and $1.6 billion, respectively. The cash used for investing activities in each of these years 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 $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. Net cash provided from financing activities totaled $1.2 billion in 2013 primarily due to an increase in capital contributions from Southern Company and an increase in long-term debt financings, partially offset by redemptions of long-term debt.

Significant balance sheet changes as of December 31, 2015 compared to 2014 included an increase in notes payable of $500 million. Income taxes receivable non-current increased $544 million due to unrecognized tax benefits associated with R&E expenditures for the 2008 through 2013 amended tax returns. Total property, plant, and equipment increased $512 million and Mirror CWIP decreased $271 million primarily associated with the construction and collections for the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information. Accumulated deferred income taxes increased $582 million primarily due to R&E tax deductions and accumulated deferred investment tax credits decreased $278 million, due to the recapture of Phase II tax credits. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Investment Tax Credits" herein for additional information. Total common stockholder's equity increased $275 million due to the receipt of capital contributions from Southern Company. Other regulatory assets, deferred, increased $140 million primarily due to the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information.

The Company's ratio of common equity to total capitalization, including long-term debt due within one year, was 47.1% in 2015 and 46.1% in 2014. 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 in 2015 by events relating to the Kemper IGCC. On December 3, 2015, the Mississippi PSC approved the In-Service Asset Rate Order which, among other things, provides for retail rate recovery of an annual revenue requirement of approximately $126 million which became effective on December 17, 2015. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Rate Case," herein for additional information. 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 – 2013 MPSC Rate Order," and " – 2015 Rate Case" herein for additional information.

In April 2015, the Company entered into two floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million, bearing interest based on one-month LIBOR. The proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million, working capital, and other general corporate purposes. The Company also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016. In addition, the Company received $275 million in equity contributions from Southern Company and issued two promissory notes for up to $676 million to Southern Company bearing interest based on one-month LIBOR. As of December 31, 2015, an aggregate of $576 million was outstanding under these promissory notes, all maturing in December 2017. On January 28, 2016, the Company issued a further promissory note for up to $275 million to Southern Company, which matures in December 2017, bearing interest based on one-month LIBOR. During January 2016, the Company borrowed $150 million pursuant to the existing promissory notes.

As of December 31, 2015 , the Company's current liabilities exceeded current assets by approximately $1.3 billion primarily due to $900 million of bank term loans scheduled to mature on April 1, 2016 and $300 million in senior notes scheduled to mature on October 15, 2016. The Company expects to refinance its 2016 debt maturities with bank term loans. The Company intends to utilize operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company to fund the remainder of the Company's capital needs.

The Company received $245 million of DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for commercial operation of the Kemper IGCC. 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 Company expects the Kemper IGCC to qualify for additional DOE grants included in the recently passed Consolidated Appropriations Act of 2015, which are expected to be used to reduce future rate impacts for customers. The ultimate outcome of this matter cannot be determined at this time.

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, 2015 , the Company had approximately $98 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2015 were as follows:

Expires			**Executable Term-Loans**		**Due Within One Year**	
2016	**Total**	**Unused**	**One Year**	**Two Years**	**Term Out**	**No Term Out**
(in millions)	*(in millions)*		*(in millions)*		*(in millions)*	
$ 220	$ 220	$ 195	$ 30	$ 15	$ 45	$ 175

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

Most of these bank credit 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. The Company is 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 $195 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, 2015 was $40 million.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional operating company under these arrangements are several and there is no cross affiliate credit support. The Company has not issued any commercial paper through this program since 2013 and does not intend to make any issuances during 2016.

The Company had no short-term borrowings in 2014. Details of short-term borrowing for 2013 and 2015 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, 2015	$500	1.4%	$372	1.3%	$515
December 31, 2013	$—	—%	$23	0.2%	$148

(*) 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 Loans

In March 2015, the Company repaid at maturity a $75 million bank term loan.

In April 2015, the Company entered into two short-term floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million. The proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million, working capital, and other general corporate purposes, including the Company's ongoing construction program. The Company also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts, other hybrid securities, and securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2015 , the Company was in compliance with its debt limits.

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

Other Obligations

In June 2015, the Company issued an additional floating rate promissory note to Southern Company. This note was for an aggregate principal amount of approximately $301 million , the amount paid by Southern Company to SMEPA pursuant to Southern Company's guarantee of the return of SMEPA's deposits in connection with the termination of the APA. In December 2015, the $301 million promissory note was amended which, among other things, changed the maturity date to December 1, 2017. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" for additional information.

In November 2015, the Company issued an additional floating rate promissory note to Southern Company in an aggregate principal amount of up to $375 million, which matures on December 1, 2017. As of December 31, 2015, the Company had borrowed $275 million under the promissory note. On January 19, 2016, the Company borrowed the remaining $100 million. Also, subsequent to December 31, 2015, the Company issued an additional floating rate promissory note to Southern Company in an aggregate principal amount of up to $275 million, which matures on December 1, 2017. The Company has borrowed $50 million under the promissory note.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that 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 sales, fuel transportation and storage, energy price risk management, and transmission. At December 31, 2015 , 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 $267 million.

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, 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 June 5, 2015, Fitch Ratings, Inc. (Fitch) downgraded the long-term issuer default rating of the Company to BBB+ from A-. Fitch maintained the negative ratings outlook for the Company.

On August 14, 2015, Moody's downgraded the senior unsecured debt rating of the Company to Baa2 from Baa1. Moody's maintained the negative ratings outlook for the Company.

On August 17, 2015, S&P downgraded the issuer rating of the Company to BBB+ from A. S&P revised its credit rating outlook from negative to stable. Separately, on August 24, 2015, S&P revised its consolidated credit rating outlook of Southern Company (including the Company) from stable to negative following the announcement of the proposed merger of a wholly-owned direct subsidiary of Southern Company with and into AGL Resources Inc.

On November 5, 2015, Moody's downgraded the senior unsecured debt rating of the Company to Baa3 from Baa2. Moody's maintained the negative ratings outlook for the Company.

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 $1 billion of long-term variable interest rate exposure at December 31, 2015 was 1.66%. 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 $10 million at January 1, 2016. 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, 2015 when compared to the year ended December 31, 2014 .

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:

	2015 Changes	2014 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (45)**	$ (5)
Contracts realized or settled	**33**	(3)
Current period changes (*)	**(35)**	(37)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (47)**	$ (45)

(*) 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:

	2015	2014
	mmBtu Volume	
	(in millions)	
Total hedge volume	**32**	54

For natural gas hedges, the weighted average swap contract cost above market prices was approximately $1.49 per mmBtu as of December 31, 2015 and $0.84 per mmBtu as of December 31, 2014 . 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, 2015 and 2014 , 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. 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, 2015 were as follows:

	Fair Value Measurements December 31, 2015		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(47)	(29)	(18)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (47)	$ (29)	$ (18)

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 $900 million will be required through December 31, 2016 to fund maturities of bank term loans scheduled to mature on April 1, 2016, $300 million in senior notes scheduled to mature on October 15, 2016, and $25 million in short-term debt. See "Sources of Capital" herein for additional information.

The construction program of the Company is currently estimated to total $787 million for 2016 , $216 million for 2017 , and $264 million for 2018 , which includes expenditures related to the construction of the Kemper IGCC of $612 million in 2016. These estimated amounts also include capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $21 million, $19 million, and $26 million for 2016 , 2017 , and 2018 , respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and 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 in place and ground water monitoring of ash ponds in accordance with the CCR Rule, which are not reflected in the capital expenditures above as these costs are associated with 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, are estimated to be $39 million, $12 million, and $11 million for the years 2016, 2017, and 2018, 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. 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

	2016	2017-2018	2019-2020	After 2020	Total
			(in millions)		
Long-term debt [a] —					
Principal	$ 725	$ 611	$ 132	$ 1,026	$ 2,494
Interest	87	132	114	670	1,003
Preferred stock dividends [b]	2	3	3	—	8
Financial derivative obligations [c]	29	18	—	—	47
Unrecognized tax benefits [d]	—	421	—	—	421
Operating leases [e]	2	2	1	—	5
Capital leases [f]	3	6	7	61	77
Purchase commitments —					
Capital [g]	752	453	—	—	1,205
Fuel [h]	142	229	191	254	816
Long-term service agreements [i]	34	65	50	215	364
Pension and other postretirement benefits plans [j]	7	14	—	—	21
Total	$ 1,783	$ 1,954	$ 498	$ 2,226	$ 6,461

(a) All amounts are reflected based on final maturity dates. 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, 2016, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

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

(d) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

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

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

(g) The Company provides estimated capital expenditures for a three-year period, including capital expenditures associated with environmental regulations. At December 31, 2015, 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, 2015.

(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 2015 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, 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 and changing fuel sources, filings with state and federal regulatory authorities, impact of the PATH Act, 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 legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, 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, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including , without limitation, IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the 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 and construction 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, 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 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, 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.

STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2015 , 2014 , and 2013
Mississippi Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 776**	$ 795	$ 799
Wholesale revenues, non-affiliates	**270**	323	294
Wholesale revenues, affiliates	**76**	107	35
Other revenues	**16**	18	17
Total operating revenues	**1,138**	1,243	1,145
Operating Expenses:			
Fuel	**443**	574	491
Purchased power, non-affiliates	**5**	18	6
Purchased power, affiliates	**7**	25	43
Other operations and maintenance	**274**	271	253
Depreciation and amortization	**123**	97	91
Taxes other than income taxes	**94**	79	81
Estimated loss on Kemper IGCC	**365**	868	1,102
Total operating expenses	**1,311**	1,932	2,067
Operating Loss	**(173)**	(689)	(922)
Other Income and (Expense):			
Allowance for equity funds used during construction	**110**	136	122
Interest expense, net of amounts capitalized	**(7)**	(45)	(36)
Other income (expense), net	**(8)**	(14)	(7)
Total other income and (expense)	**95**	77	79
Loss Before Income Taxes	**(78)**	(612)	(843)
Income taxes (benefit)	**(72)**	(285)	(368)
Net Loss	**(6)**	(327)	(475)
Dividends on Preferred Stock	**2**	2	2
Net Loss After Dividends on Preferred Stock	**$ (8)**	$ (329)	$ (477)

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

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2015 , 2014 , and 2013
Mississippi Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Net Loss	**$ (6)**	$ (327)	$ (475)
Other comprehensive income (loss):			
Qualifying hedges:			
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**1**	1	1
Total other comprehensive income (loss)	**1**	1	1
Comprehensive Loss	**$ (5)**	$ (326)	$ (474)

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2015 , 2014 , and 2013
Mississippi Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Activities:			
Net loss	**$ (6)**	$ (327)	$ (475)
Adjustments to reconcile net loss to net cash provided from operating activities —			
Depreciation and amortization, total	**126**	104	92
Deferred income taxes	**777**	145	(396)
Investment tax credits	**(210)**	(38)	144
Allowance for equity funds used during construction	**(110)**	(136)	(122)
Pension, postretirement, and other employee benefits	**10**	(29)	14
Regulatory assets associated with Kemper IGCC	**(61)**	(72)	(35)
Estimated loss on Kemper IGCC	**365**	868	1,102
Income taxes receivable, non-current	**(544)**	—	—
Other, net	**(2)**	18	107
Changes in certain current assets and liabilities —			
-Receivables	**28**	(22)	(25)
-Fossil fuel stock	**(4)**	13	63
-Materials and supplies	**(13)**	(15)	(11)
-Prepaid income taxes	**(35)**	(50)	17
-Other current assets	**(1)**	(4)	(4)
-Other accounts payable	**(34)**	33	13
-Accrued interest	**(2)**	29	17
-Accrued taxes	**(11)**	39	11
-Over recovered regulatory clause revenues	**96**	(18)	(59)
-Mirror CWIP	**(271)**	180	—
-Customer liability associated with Kemper refunds	**73**	—	—
-Other current liabilities	**2**	17	(5)
Net cash provided from operating activities	**173**	735	448
Investing Activities:			
Property additions	**(857)**	(1,257)	(1,641)
Investment in restricted cash	**—**	(11)	—
Distribution of restricted cash	**—**	11	—
Cost of removal net of salvage	**(14)**	(13)	(10)
Construction payables	**(9)**	(50)	(50)
Proceeds from asset sales	**—**	—	79
Other investing activities	**(26)**	(20)	19
Net cash used for investing activities	**(906)**	(1,340)	(1,603)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	**277**	451	1,077
Bonds — Other	**—**	23	42
Interest-bearing refundable deposit	**—**	125	—
Long-term debt issuance to parent company	**275**	220	—
Other long-term debt issuances	**—**	250	475
Short-term borrowings	**505**	—	—
Redemptions —			
Bonds — Other	**—**	(34)	(83)
Senior notes	**—**	—	(50)
Other long-term debt	**(350)**	(220)	(125)
Return of paid in capital	**—**	(220)	(105)

Payment of preferred stock dividends		**(2)**		(2)		(2)
Payment of common stock dividends		**—**		—		(72)
Other financing activities		**(7)**		—		(2)
Net cash provided from financing activities		**698**		593		1,155
Net Change in Cash and Cash Equivalents		**(35)**		(12)		—
Cash and Cash Equivalents at Beginning of Year		**133**		145		145
Cash and Cash Equivalents at End of Year	**$**	**98**	$	133	$	145
Supplemental Cash Flow Information:						
Cash paid (received) during the period for —						
Interest (net of $66, $69, and $54 capitalized, respectively)	**$**	**45**	$	7	$	20
Income taxes (net of refunds)		**(33)**		(379)		(134)
Noncash transactions —						
Accrued property additions at year-end		**105**		114		165
Capital lease obligation		**—**		—		83
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, 2015 and 2014
Mississippi Power Company 2015 Annual Report

Assets		**2015**		2014
		(in millions)		
Current Assets:				
Cash and cash equivalents	$	**98**	$	133
Receivables —				
Customer accounts receivable		**26**		43
Unbilled revenues		**36**		35
Other accounts and notes receivable		**10**		11
Affiliated companies		**20**		51
Income taxes receivable, current		**20**		—
Fossil fuel stock, at average cost		**104**		100
Materials and supplies, at average cost		**75**		62
Other regulatory assets, current		**95**		73
Prepaid income taxes		**39**		70
Other current assets		**8**		5
Total current assets		**531**		583
Property, Plant, and Equipment:				
In service		**4,886**		4,378
Less accumulated provision for depreciation		**1,262**		1,173
Plant in service, net of depreciation		**3,624**		3,205
Construction work in progress		**2,254**		2,161
Total property, plant, and equipment		**5,878**		5,366
Other Property and Investments		**11**		5
Deferred Charges and Other Assets:				
Deferred charges related to income taxes		**290**		226
Other regulatory assets, deferred		**525**		385
Income taxes receivable, non-current		**544**		—
Accumulated deferred income taxes		**—**		33
Other deferred charges and assets		**61**		44
Total deferred charges and other assets		**1,420**		688
Total Assets	$	**7,840**	$	6,642

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

BALANCE SHEETS
At December 31, 2015 and 2014
Mississippi Power Company 2015 Annual Report

Liabilities and Stockholder's Equity	2015	2014
	(in millions)	
Current Liabilities:		
Securities due within one year	$ 728	$ 778
Notes payable	500	—
Interest-bearing refundable deposits	—	275
Accounts payable —		
Affiliated	85	86
Other	135	178
Customer deposits	16	15
Accrued taxes —		
Accrued income taxes	—	142
Other accrued taxes	85	84
Accrued interest	18	76
Accrued compensation	26	26
Over recovered regulatory clause liabilities	96	1
Mirror CWIP	—	271
Customer liability associated with Kemper refunds	73	—
Other current liabilities	74	46
Total current liabilities	1,836	1,978
Long-Term Debt (See accompanying statements)	1,886	1,621
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	762	180
Deferred credits related to income taxes	8	9
Accumulated deferred investment tax credits	5	283
Employee benefit obligations	153	148
Asset retirement obligations	154	48
Unrecognized tax benefits	368	2
Other cost of removal obligations	165	166
Other regulatory liabilities, deferred	71	64
Other deferred credits and liabilities	40	26
Total deferred credits and other liabilities	1,726	926
Total Liabilities	5,448	4,525
Cumulative Redeemable Preferred Stock (See accompanying statements)	33	33
Common Stockholder's Equity (See accompanying statements)	2,359	2,084
Total Liabilities and Stockholder's Equity	$ 7,840	$ 6,642
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2015 and 2014
Mississippi Power Company 2015 Annual Report

	2015	2014	2015	2014
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
2.35% due 2016	**$ 300**	$ 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**	775		
Total long-term notes payable	**1,565**	1,915		
Other long-term debt —				
Pollution control revenue bonds —				
5.15% due 2028	**43**	43		
Variable rate (0.16% at 1/1/16) due 2020	**7**	7		
Variable rates (0.10% to 0.11% at 1/1/16) due 2025-2028	**33**	33		
Plant Daniel revenue bonds (7.13%) due 2021	**270**	270		
Long-term debt payable to parent company (1.49% to 1.74%) due 2017	**576**	—		
Total other long-term debt	**929**	353		
Capitalized lease obligations	**77**	79		
Unamortized debt premium	**53**	63		
Unamortized debt discount	**(2)**	(2)		
Unamortized debt issuance expense	**(8)**	(9)		
Total long-term debt (annual interest requirement — $87 million)	**2,614**	2,399		
Less amount due within one year	**728**	778		
Long-term debt excluding amount due within one year	**1,886**	1,621	**44.1%**	43.3%
Cumulative Redeemable Preferred Stock:				
$100 par value —				
Authorized — 1,244,139 shares				
Outstanding — 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $2 million)	**33**	33	**0.8**	0.9
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 1,130,000 shares				
Outstanding — 1,121,000 shares	**38**	38		
Paid-in capital	**2,893**	2,612		
Accumulated deficit	**(566)**	(559)		
Accumulated other comprehensive loss	**(6)**	(7)		
Total common stockholder's equity	**2,359**	2,084	**55.1**	55.8
Total Capitalization	**$ 4,278**	$ 3,738	**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, 2015 , 2014 , and 2013
Mississippi Power Company 2015 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, 2012	1	$ 38	$ 1,401	$ 319	$ (9)	$ 1,749
Net loss after dividends on preferred stock	—	—	—	(477)	—	(477)
Capital contributions from parent company	—	—	976	—	—	976
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(72)	—	(72)
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**

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

NOTES TO FINANCIAL STATEMENTS
Mississippi Power Company 2015 Annual Report

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

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

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

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers* , revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $9 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 9 for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07) *,* effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the Company. See Note 2 for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid income taxes of $121 million with $105 million to non-current accumulated deferred income taxes and $16 million to other deferred charges in the Company's December 31, 2014 balance sheet.

Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 for disclosures impacted by ASU 2015-17.

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 $295 million , $259 million , and $205 million during 2015 , 2014 , and 2013 , 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 $11 million , $13 million , and $13 million in 2015 , 2014 , and 2013 , respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility, which were $8 million , $34 million , and $27 million in 2015 , 2014 , and 2013 , 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 $27 million , $31 million , and $17 million in 2015 , 2014 , and 2013 , respectively. See Note 4 for additional information.

The Company also provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2015 , 2014 , or 2013 .

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

Regulatory Assets and Liabilities

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

NOTES (continued)
Mississippi Power Company 2015 Annual Report

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

	2015	2014	Note
		(in millions)	
Retiree benefit plans – regulatory assets	**$ 163**	$ 169	(a,g)
Property damage	**(64)**	(62)	(i)
Deferred income tax charges	**291**	227	(c)
Remaining net book value of retired assets	**36**	2	(b)
Property tax	**27**	28	(d)
Vacation pay	**11**	11	(e,g)
Plant Daniel Units 3 and 4 regulatory assets	**29**	23	(j)
Other regulatory assets	**16**	18	(b)
Fuel-hedging (realized and unrealized) losses	**50**	47	(f,g)
Asset retirement obligations	**70**	11	(c)
Other cost of removal obligations	**(167)**	(166)	(c)
Kemper IGCC regulatory assets	**216**	148	(h)
Mirror CWIP	**—**	(271)	(h)
Other regulatory liabilities	**(11)**	(13)	(b)
Total regulatory assets (liabilities), net	**$ 667**	$ 172	

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

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

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

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

(d) Recovered through the ad valorem tax adjustment clause over a 12 -month period beginning in April of the following year. See Note 3 under "Ad Valorem Tax Adjustment" for additional information.

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

(f) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed 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) 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) Deferred and amortized over a 10 -year period beginning October 2021, as approved by the Mississippi PSC for the difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term.

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 (DOE Grants). Through December 31, 2015 , the Company has received grant funds of $245 million , used for the construction of the Kemper IGCC, which is reflected in the Company's financial statements as a reduction to the Kemper IGCC capital costs. An additional $25 million is expected to be received for its initial operation. See Note 3 under "Kemper IGCC Schedule and Cost Estimate" for additional information.

NOTES (continued)
Mississippi Power Company 2015 Annual Report

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 21.0% of the Company's total operating revenues in 2015 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 for the collection of the Company’s cost-based MRA electric tariff customers, the Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

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:

	2015	2014
	(in millions)	
Generation	**$ 2,723**	$ 2,293
Transmission	**688**	665
Distribution	**891**	854
General	**503**	485
Plant acquisition adjustment	**81**	81
Total plant in service	**$ 4,886**	$ 4,378

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 operation and maintenance expenses are charged to fuel stock and recovered through the Company's fuel clause. Through second quarter 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 to be recovered over the life of the Kemper IGCC. Beginning in the third quarter 2015, the Company began expensing a portion of these ongoing cost previously deferred as regulatory assets. 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 4.7% in 2015 , 3.3% in 2014 , and 3.4% in 2013 . The increase in the 2015 depreciation rate is primarily due to an asset retirement obligation (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. On December 3, 2015, the Mississippi PSC approved the study filed in 2014, 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.

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 the second quarter 2015, depreciation associated with the combined cycle and the associated common facilities portion of the Kemper IGCC was deferred as a regulatory asset to be recovered over the life of the Kemper IGCC. Beginning in the third quarter 2015, the Company began expensing certain ongoing project costs, including depreciation, that previously were deferred as regulatory assets. 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 on April 17, 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.

NOTES (continued)
Mississippi Power Company 2015 Annual Report

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

	2015	2014
	(in millions)	
Balance at beginning of year	**$ 48**	$ 42
Liabilities incurred	**101**	—
Liabilities settled	**(3)**	(3)
Accretion	**4**	2
Cash flow revisions	**27**	7
Balance at end of year	**$ 177**	$ 48

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, 2015 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 in place. 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, 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.

The increase in cash flow revisions in 2014 related to the Company's AROs associated with the Plant Watson landfill and Plant Greene County asbestos.

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 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 5.99% , 6.91% , and 6.89% for the years ended December 31, 2015 , 2014 , and 2013 , respectively. AFUDC equity was $110 million , $136 million , and $122 million in 2015 , 2014 , and 2013 , 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, 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. In each of 2015 , 2014 , and 2013 , the Company made retail accruals of $3 million . The Company accrued $0.3 million annually in 2015 , 2014 , and 2013 for the wholesale jurisdiction. As of December 31, 2015 , the property damage reserve balances were $63 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 appropriate, at weighted-average cost when utilized.

Fuel Inventory

Fuel inventory includes the average cost of coal, lignite, natural gas, oil, transportation, and emissions allowances. Fuel is charged to inventory when purchased, except for the cost of owning and operating the lignite mine related to the Kemper IGCC which is charged to inventory as incurred, and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates 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 are recorded in CWIP. Any ineffectiveness arising from these would be recognized currently in net income; however, the Company has regulatory approval allowing it to defer any ineffectiveness arising from hedging instruments relating to the Kemper IGCC to a regulatory asset. Other derivative contracts 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.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2015 .

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

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

Comprehensive Income

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

Variable Interest Entities

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

The Company is required to provide financing for all costs associated with the mine development and operation under a contract with Liberty Fuels Company, LLC, a subsidiary of North American Coal Corporation (Liberty Fuels), in conjunction with the construction of the Kemper IGCC. Liberty Fuels qualifies as a VIE for which the Company is the primary beneficiary. For the year ended December 31, 2015 , the VIE consolidation resulted in an ARO asset and associated liability in the amounts of $21 million and $25 million , respectively. For the year ended December 31, 2014 , the VIE consolidation resulted in an ARO and an associated liability in the amounts of $21 million and $24 million , respectively. For the year ended December 31, 2013 , the VIE consolidation resulted in an ARO and associated liability in the amounts of $21 million and $23 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). No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2016 . 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, 2016 , 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:	2015	2014	2013
Pension plans			
Discount rate – interest costs	**4.17%**	5.01%	4.26%
Discount rate – service costs	**4.49**	5.01	4.26
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**3.59**	3.59	3.59
Other postretirement benefit plans			
Discount rate – interest costs	**4.03%**	4.85%	4.04%
Discount rate – service costs	**4.38**	4.85	4.04
Expected long-term return on plan assets	**7.23**	7.30	7.04
Annual salary increase	**3.59**	3.59	3.59

Assumptions used to determine benefit obligations:	2015	2014
Pension plans		
Discount rate	**4.69%**	4.17%
Annual salary increase	**4.46**	3.59
Other postretirement benefit plans		
Discount rate	**4.47%**	4.03%
Annual salary increase	**4.46**	3.59

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

For purposes of its December 31, 2015 measurement date, the Company adopted new mortality tables for its pension and other postretirement benefit plans, which reflect decreased life expectancies in the U.S. The adoption of new mortality tables reduced the projected benefit obligations for the Company's pension and other postretirement benefit plans by approximately $9 million and $2 million , respectively.

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, 2015 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2024
Post-65 medical	5.50	4.50	2024
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, 2015 as follows:

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

Pension Plans

The total accumulated benefit obligation for the pension plans was $447 million at December 31, 2015 and $462 million at December 31, 2014 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 513**	$ 409
Service cost	**13**	10
Interest cost	**21**	20
Benefits paid	**(22)**	(17)
Actuarial loss (gain)	**(25)**	91
Balance at end of year	**500**	513
Change in plan assets		
Fair value of plan assets at beginning of year	**446**	387
Actual return on plan assets	**4**	40
Employer contributions	**2**	36
Benefits paid	**(22)**	(17)
Fair value of plan assets at end of year	**430**	446
Accrued liability	**$ (70)**	$ (67)

At December 31, 2015 , the projected benefit obligations for the qualified and non-qualified pension plans were $470 million and $30 million , respectively. All pension plan assets are related to the qualified pension plan.

NOTES (continued)
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Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's pension plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 144**	$ 151
Other current liabilities	**(3)**	(2)
Employee benefit obligations	**(67)**	(65)

Presented below are the amounts included in regulatory assets at December 31, 2015 and 2014 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 2016 .

	2015	2014	Estimated Amortization in 2016
		(in millions)	
Prior service cost	**$ 2**	$ 3	**$ 1**
Net loss	**142**	148	**7**
Regulatory assets	**$ 144**	$ 151	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 151**	$ 78
Net (gain) loss	**4**	79
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	(1)
Amortization of net gain (loss)	**(10)**	(5)
Total reclassification adjustments	**(11)**	(6)
Total change	**(7)**	73
Ending balance	**$ 144**	$ 151

Components of net periodic pension cost were as follows:

	2015	2014	2013
		(in millions)	
Service cost	**$ 13**	$ 10	$ 11
Interest cost	**21**	20	18
Expected return on plan assets	**(33)**	(29)	(27)
Recognized net loss	**10**	5	10
Net amortization	**1**	1	1
Net periodic pension cost	**$ 12**	$ 7	$ 13

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.

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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, 2015 , estimated benefit payments were as follows:

		Benefit Payments
		(in millions)
2016	$	20
2017		21
2018		22
2019		24
2020		25
2021 to 2025		146

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

		2015		2014
		(in millions)		
Change in benefit obligation				
Benefit obligation at beginning of year	**$**	**96**	$	81
Service cost		**1**		1
Interest cost		**4**		4
Benefits paid		**(5)**		(5)
Actuarial loss (gain)		**(1)**		14
Plan amendment		**1**		—
Retiree drug subsidy		**1**		1
Balance at end of year		**97**		96
Change in plan assets				
Fair value of plan assets at beginning of year		**24**		23
Actual return on plan assets		**—**		2
Employer contributions		**3**		3
Benefits paid		**(4)**		(4)
Fair value of plan assets at end of year		**23**		24
Accrued liability	**$**	**(74)**	$	(72)

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's other postretirement benefit plans consist of the following:

		2015		2014
		(in millions)		
Other regulatory assets, deferred	**$**	**21**	$	18
Other regulatory liabilities, deferred		**(3)**		(2)
Employee benefit obligations		**(74)**		(72)

NOTES (continued)
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Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2015 and 2014 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2016 .

	2015	2014	Estimated Amortization in 2016
		(in millions)	
Prior service cost	$ —	$ (2)	$ —
Net (gain) loss	(18)	18	1
Net regulatory assets	$ (18)	$ 16	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	$ 16	$ 2
Net (gain) loss	—	14
Change in prior service costs	3	—
Reclassification adjustments:		
Amortization of net gain (loss)	(1)	—
Total reclassification adjustments	(1)	—
Total change	2	14
Ending balance	$ 18	$ 16

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

	2015	2014	2013
		(in millions)	
Service cost	$ 1	$ 1	$ 1
Interest cost	4	4	4
Expected return on plan assets	(2)	(2)	(1)
Net amortization	1	—	—
Net periodic postretirement benefit cost	$ 4	$ 3	$ 4

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)	
2016	$ 6	$ —	$ 6
2017	6	(1)	5
2018	6	(1)	5
2019	7	(1)	6
2020	7	(1)	6
2021 to 2025	36	(2)	34

NOTES (continued)
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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, 2015 and 2014 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2015**	2014
Pension plan assets:			
Domestic equity	26%	**30%**	30%
International equity	25	**23**	23
Fixed income	23	**23**	27
Special situations	3	**2**	1
Real estate investments	14	**16**	14
Private equity	9	**6**	5
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	21%	**24%**	24%
International equity	20	**18**	19
Domestic fixed income	38	**38**	41
Special situations	3	**2**	1
Real estate investments	11	**13**	11
Private equity	7	**5**	4
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, 2015 and 2014 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

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

NOTES (continued)
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The fair values of pension plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 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*	$ 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.

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As of December 31, 2014:	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*	$ 78	$ 32	$ —	$ —	$ 110
International equity*	49	45	—	—	94
Fixed income:					
U.S. Treasury, government, and agency bonds	—	32	—	—	32
Mortgage- and asset-backed securities	—	9	—	—	9
Corporate bonds	—	53	—	—	53
Pooled funds	—	24	—	—	24
Cash equivalents and other	—	30	—	—	30
Real estate investments	14	—	—	51	65
Private equity	—	—	—	26	26
Total	$ 141	$ 225	$ —	$ 77	$ 443

* 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.

NOTES (continued)
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The fair values of other postretirement benefit plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 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.

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	Fair Value Measurements Using				
As of December 31, 2014:	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	$ 2	$ —	$ —	$ 5
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	—	—	2
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$ 7	$ 14	$ —	$ 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.

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 2015 , 2014 , and 2013 were $5 million , $5 million , and $4 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has 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 regulatory mechanisms.

FERC Matters

Municipal and Rural Associations Tariff

In 2012, the Company entered into a settlement agreement with its wholesale customers with respect to the Company's request for revised rates under the wholesale cost-based electric tariff. The settlement agreement provided that base rates under the cost-based electric tariff increase by approximately $23 million over a 12 -month period with revised rates effective April 1, 2012. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase was due to a change in the recovery methodology for the return on the Kemper IGCC CWIP. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The tariff customers specifically agreed to the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (i) the accounting for Kemper IGCC-related costs that cannot be capitalized, (ii) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (iii) the establishment of a regulatory asset for certain potential plant retirement costs.

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

In 2013, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an additional increase in the MRA cost-based electric tariff, which was accepted by the FERC in 2013. The 2013 settlement agreement provided that base rates under the MRA cost-based electric tariff will increase by approximately $24 million annually, effective April 1, 2013.

In March 2014, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an increase in the MRA cost-based electric tariff. The settlement agreement, accepted by the FERC in May 2014, provided that base rates under the MRA cost-based electric tariff increased approximately $10 million annually, effective May 1, 2014.

Included in this settlement agreement, an adjustment to the Company's wholesale revenue requirement in a subsequent rate proceeding was allowed 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.

On May 13, 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. The additional resulting AFUDC is estimated to be approximately $14 million annually, of which $11 million relates to the Kemper IGCC.

Fuel Cost Recovery

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2016, the wholesale MRA fuel rate decreased $47 million annually. Effective February 1, 2016, the wholesale MB fuel rate decreased $2 million annually. At December 31, 2015 , the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $24 million compared to an immaterial balance at December 31, 2014 .

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 operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional 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 operating companies and in some adjacent areas. The FERC directed the traditional 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 operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter 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.

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 . An annual report addressing the performance of all energy efficiency programs is required.

In June 2014, the Mississippi PSC approved the Company's 2014 Energy Efficiency Quick Start Plan filing, which includes a portfolio of energy efficiency programs. In November 2014, the Mississippi PSC approved the Company's revised compliance filing, which included an increase of $7 million in retail revenues for the period December 2014 through December 2015.

Performance Evaluation Plan

The Company’s retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on projected revenue requirement, and the PEP lookback filing, which is filed after the year and allows for review of the actual revenue requirement compared to the projected filing. PEP was designed with the objective to reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high. PEP is a mechanism for rate adjustments based on three indicators: price, customer satisfaction, and service reliability.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. I n 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 certain costs included in the 2010 PEP lookback filing, which are currently 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 March 2014 and 2015, the Company submitted its annual PEP lookback filings for 2013 and 2014, respectively, which each indicated no surcharge or refund. The Mississippi PSC suspended each of the filings to allow more time for review.

In June 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.

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. The Company's portion of the cost is expected to be recovered through the ECO Plan following the scheduled completion of the project. As of December 31, 2015 , total project expenditures were $637 million , of which the Company's portion was $325 million , excluding AFUDC of $36 million .

In 2013, the Mississippi PSC approved the Company’s 2013 ECO Plan filing which proposed no change in rates.

In August 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 August 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. 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 on April 16, 2015), and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016.

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. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. As of December 31, 2015, $5 million of Plant Greene County costs and $36 million of costs related to Plant Watson have been reclassified as regulatory assets. These costs are expected to be recovered through the ECO plan and other existing cost recovery mechanisms. Additional costs associated with the remaining net book value of coal-related equipment will be reclassified to a regulatory asset at the time of retirement for Plants Watson and Greene County in 2016. Approved regulatory asset costs will be amortized over a period to be determined by the Mississippi PSC. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

On December 3, 2015, the Mississippi PSC approved the Company's revised ECO filing for 2015, which indicated no change in revenue.

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 21, 2016, which will result in an annual revenue decrease of approximately $120 million . At December 31, 2015 , the amount of over-recovered retail fuel costs included in the balance sheets was $71 million compared to a $3 million under-recovered balance at December 31, 2014 .

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 September 1, 2015, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing effective September 18, 2015, which included an annual rate decrease of 0.35% , or $2 million in annual retail revenues, primarily due to average millage rates.

System Restoration Rider

On October 6, 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. The ultimate outcome of this matter cannot be determined at this time.

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

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of the Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation 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 planned 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 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

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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 using natural gas in August 2014 and currently expects to place the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, in service during the third quarter 2016.

Recovery of the costs subject to the cost cap and 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) remains subject to review and approval by the Mississippi PSC. The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision), and actual costs incurred as of December 31, 2015 , are as follows:

Cost Category	2010 Project Estimate [f]	Current Cost Estimate [a]	Actual Costs
		(in billions)	
Plant Subject to Cost Cap [b][g]	$ 2.40	$ 5.29	**$ 4.83**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC [c]	0.17	0.69	**0.59**
Combined Cycle and Related Assets Placed in Service – Incremental [d][g]	—	0.01	**0.01**
General Exceptions	0.05	0.10	**0.09**
Deferred Costs [e][g]	—	0.20	**0.17**
Total Kemper IGCC	$ 2.97	$ 6.63	**$ 6.03**

(a) Amounts in the Current Cost Estimate reflect estimated costs through August 31, 2016.

(b) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , net of the DOE Grants and excluding the Cost Cap Exceptions. 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. The Current Cost Estimate and the Actual Costs reflect 100% of the costs of the Kemper IGCC. See note (g) for additional information.

(c) The Company's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs." The current estimate 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.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information.

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

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

(g) Beginning in the third quarter 2015, certain costs, including debt carrying costs (associated with assets placed in service and other non-CWIP accounts), that previously were deferred as regulatory assets are now being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2015.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2015 , $3.47 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.41 billion), $2 million in other property and investments, $69 million in fossil fuel stock, $45 million in materials and supplies, $21 million in other regulatory assets, current, $195 million in other regulatory assets, deferred, and $11 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 DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate above the cost cap of $365 million ($226 million after tax), $868 million ($536 million after tax), and $1.1 billion ($681 million after tax) in 2015, 2014, and 2013, respectively. The increases to the cost estimate in

2015 primarily reflect costs for the extension of the Kemper IGCC's projected in-service date through August 31, 2016, increased efforts related to scope modifications, additional labor costs in support of start-up and operational readiness activities, and system repairs and modifications after startup testing and commissioning activities identified necessary remediation of equipment installation, fabrication, and design issues, including the refractory lining inside the gasifiers; the lignite feed and dryer systems; and the syngas cooler vessels. Any extension of the in-service date beyond August 31, 2016 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 August 31, 2016 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 $13 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 $2 million per month. For additional information, see "2015 Rate Case" herein.

The Company's analysis of the time needed to complete the start-up and commissioning activities for the Kemper IGCC will continue until the remaining Kemper IGCC assets are placed in service. Further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, 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 for this first-of-a-kind technology (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). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of operations and these changes could be material.

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" herein for additional information regarding the Company's MRA cost-based tariff relating to recovery of a portion of the Kemper IGCC costs from the Company's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See "Income Tax Matters" herein for additional tax information related to the Kemper IGCC.

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

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN. The Company expects the Mississippi PSC to apply operational parameters in connection with 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.

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.

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. The Company will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts.

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order. 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 discussed below.

2015 Rate Case

As a result of the 2015 Court decision, on July 10, 2015, the Company filed a supplemental filing including a request for interim rates (Supplemental Notice) with the Mississippi PSC which presented an alternative rate proposal (In-Service Asset Proposal) for consideration by the Mississippi PSC. The In-Service Asset Proposal was based upon the test period of June 2015 to May 2016, was 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, and was designed to collect approximately $159 million annually. On August 13, 2015, the Mississippi PSC approved the implementation of interim rates that became effective with the first billing cycle in September, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order) adopting in full a stipulation (the 2015 Stipulation) entered into between the Company and the MPUS regarding the In-Service Asset Proposal. Consistent with the 2015 Stipulation, the In-Service Asset Rate Order provides 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 during the test period. The In-Service Asset Rate Order also includes a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excludes the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA . See "Termination of Proposed Sale of Undivided Interest to SMEPA" herein for additional information.

With implementation of the new rate on December 17, 2015, the interim rates were terminated and the Company recorded a customer refund of approximately $11 million in December 2015 for the difference between the interim rates collected and the permanent rates. The refund is required to be completed by March 16, 2016.

Pursuant to the In-Service Asset Rate Order, the Company is required to file a subsequent rate request within 18 months . As part of the filing, the Company expects to request recovery of certain costs that the Mississippi PSC had excluded from the revenue requirement calculation.

On February 25, 2016, Greenleaf CO2 Solutions, LLC filed a notice of appeal of the In-Service Asset Rate Order with the Court. The Company believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on the Company's results of operations, financial condition, and liquidity. The ultimate outcome of this matter cannot be determined at this time.

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 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.

The Company expects to seek additional rate relief to address recovery of the remaining Kemper IGCC assets. In addition to current estimated costs at December 31, 2015 of $6.63 billion , the Company anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

The Company expects the Kemper IGCC to qualify for additional DOE grants included in the recently passed Consolidated Appropriations Act of 2015, which are expected to be used to reduce future rate impacts for customers. The ultimate outcome of this matter cannot be determined at this time.

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, in connection with the implementation of interim rates, the Company began expensing certain ongoing project costs and certain 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. As of December 31, 2015, the balance associated with these regulatory assets was $120 million . Other regulatory assets associated with the remainder of the Kemper IGCC totaled $96 million as of December 31, 2015 . The amortization period for these assets is expected to be determined by the Mississippi PSC in future rate proceedings following completion of construction and start-up of the Kemper IGCC and related prudence reviews.

See "2013 MPSC Rate Order" herein for information related to the July 7, 2015 Mississippi PSC order terminating the Mirror CWIP rate and requiring refund of collections under Mirror CWIP.

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. As of December 31, 2015, the Company recorded a related regulatory liability of approximately $2 million . See "2015 Rate Case" herein for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation 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 has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide Denbury and Treetop with termination rights as the Company has not satisfied its contractual obligation to deliver captured CO_2 by May 11, 2015. Since May 11, 2015, the Company has been engaged in ongoing discussions with its off-takers regarding the status of the CO_2 delivery schedule as well as other issues related to the CO_2 agreements. As a result of discussions with Treetop, on August 3, 2015, the Company agreed to amend certain provisions of their agreement that do not affect pricing or minimum purchase quantities. Potential requirements imposed on CO_2 off-takers under the Clean Power Plan (if ultimately enacted in its current form, pending resolution of litigation) and the potential adverse financial impact of low oil prices on the off-takers increase the risk that the CO_2 contracts may be terminated or materially modified. Any termination or material modification of these agreements could 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. Additionally, if the contracts remain in place, sustained oil price reductions could result in significantly lower revenues than the Company 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 to SMEPA

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. On May 20, 2015, SMEPA notified the Company that it was terminating the agreement. The Company had previously received a total of $275 million of deposits from SMEPA that were returned by Southern Company to SMEPA, with interest of approximately $26 million , on June 3, 2015, as a result of the termination, pursuant to its guarantee obligation. Subsequently, the Company issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures December 1, 2017.

The In-Service Asset Proposal and the related rates approved by the Mississippi PSC excluded any costs associated with the 15% undivided interest. The Company continues to evaluate its alternatives with respect to its investment and the related costs associated with the 15% undivided interest.

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years . The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 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 50% bonus depreciation is expected to result in approximately $3 million of positive cash flows related to the combined cycle and associated common facilities portion of the Kemper IGCC for the 2015 tax year and approximately $360 million for the 2016 tax year, which may not all be realized in 2016 due to a projected net operating loss (NOL) on Southern Company's 2016 consolidated income tax return, and is dependent upon placing the remainder of the Kemper IGCC in service in 2016. See "Kemper IGCC Schedule and Cost Estimate" herein for additional information. The ultimate outcome of this matter cannot be determined at this time.

Investment Tax Credits

The IRS allocated $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 April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. As a result of the schedule extension for the Kemper IGCC, the Phase II tax credits have been recaptured.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations for 2013, 2014, and 2015. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures. Due to the uncertainty related to this tax position, the Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $423 million as of December 31, 2015 . See "Bonus Depreciation" herein and Note 5 under "Unrecognized Tax Benefits" for additional information. 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.

In August 2014, a decision was made to cease coal operations at Greene County Steam Plant and convert to natural gas no later than April 16, 2016. As a result, active construction projects related to these assets were cancelled in September 2014. Associated amounts in CWIP of $6 million , reflecting the Company's share of the costs, were subsequently transferred to regulatory assets. See Note 3 under "Retail Regulatory Matters-Environmental Compliance Overview Plan" for additional information.

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At December 31, 2015 , 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%	$ 152	$ 56	$ 13
Daniel				
Units 1 and 2	50%	$ 686	$ 160	$ 10

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:

	2015	2014	2013
		(in millions)	
Federal —			
Current	**$ (768)**	$ (431)	$ 23
Deferred	**704**	183	(343)
	(64)	(248)	(320)
State —			
Current	**(81)**	1	5
Deferred	**73**	(38)	(53)
	(8)	(37)	(48)
Total	**$ (72)**	$ (285)	$ (368)

NOTES (continued)
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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:

	2015	2014
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$ 1,618	$ 1,068
ECM under recovered	13	—
Regulatory assets associated with AROs	71	19
Pensions and other benefits	30	35
Regulatory assets associated with employee benefit obligations	66	68
Regulatory assets associated with the Kemper IGCC	86	62
Rate differential	115	89
Federal effect of state deferred taxes	—	1
Fuel clause under recovered	—	3
Other	163	52
Total	2,162	1,397
Deferred tax assets —		
Fuel clause over recovered	51	—
Estimated loss on Kemper IGCC	451	631
Pension and other benefits	92	92
Property insurance	25	24
Premium on long-term debt	18	21
Unbilled fuel	16	15
AROs	71	19
Interest rate hedges	4	5
Kemper rate factor - regulatory liability retail	—	108
Property basis difference	451	263
ECM over recovered	—	1
Deferred state tax assets	152	57
Deferred federal tax assets	48	—
Federal effect of state deferred taxes	8	—
Other	13	15
Total	1,400	1,251
Total deferred tax liabilities, net	762	146
Deferred state tax asset	—	34
Accumulated deferred income taxes	$ 762	$ 180

On November 20, 2015, the FASB issued ASU 2015-17, which simplifies the presentation of deferred income taxes. The new guidance resulted in a reclassification from prepaid income taxes of $121 million with $105 million to non-current accumulated deferred income taxes and $16 million to other deferred charges in the Company's December 31, 2014 balance sheet. See Note 1 under "Recently Issued Accounting Standards" for additional information.

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation in 2015 and 2014.

At December 31, 2015 , the tax-related regulatory assets were $291 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 to taxes applicable to capitalized interest.

At December 31, 2015 , the tax-related regulatory liabilities were $8 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 2015, 2014, and 2013.

At December 31, 2015, the Company had state of Mississippi NOL carryforwards totaling approximately $3 billion , resulting in deferred tax assets of approximately $97 million . The NOLs will expire between 2033 and 2035, but are expected to be fully utilized by 2028.

Effective Tax Rate

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

	2015	2014	2013
Federal statutory rate	**(35.0)%**	(35.0)%	(35.0)%
State income tax, net of federal deduction	**(6.3)**	(4.0)	(3.7)
Non-deductible book depreciation	**1.3**	0.1	0.1
AFUDC-equity	**(49.6)**	(7.8)	(5.0)
Other	**(2.9)**	0.1	(0.1)
Effective income tax rate (benefit rate)	**(92.5)%**	(46.6)%	(43.7)%

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, offset by a decrease in non-taxable AFUDC equity. The increase in the Company's 2014 effective tax rate (benefit rate), as compared to 2013, is primarily due to an increase in non-taxable AFUDC equity.

Unrecognized Tax Benefits

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

	2015	2014	2013
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 165**	$ 4	$ 6
Tax positions increase from current periods	**32**	58	—
Tax positions increase/(decrease) from prior periods	**224**	103	(2)
Balance at end of year	**$ 421**	$ 165	$ 4

The tax positions increase from current periods and prior periods for 2015 and 2014 relates to deductions for R&E expenditures associated with the Kemper IGCC. See "Section 174 Research and Experimental Deduction" herein for more information. The tax positions decrease from prior periods for 2013 relates primarily to the Company's compliance with final U.S. Treasury regulations that resulted in a tax accounting method change for repairs.

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

	2015	2014	2013
		(in millions)	
Tax positions impacting the effective tax rate	**$ (2)**	$ 4	$ 4
Tax positions not impacting the effective tax rate	**423**	161	—
Balance of unrecognized tax benefits	**$ 421**	$ 165	$ 4

The tax positions impacting the effective tax rate for 2015 primarily relate to a graduated tax rate adjustment on the 2014 federal income tax return. The tax positions impacting the effective tax rate for 2014 and 2013 primarily relate to state income tax credits. The tax positions not impacting the effective tax rate for 2015 and 2014 relate to deductions for R&E expenditures associated with the Kemper IGCC. See "Section 174 Research and Experimental Deduction" herein for more information.

Accrued interest for unrecognized tax benefits was as follows:

	2015	2014	2013
		(in millions)	
Interest accrued at beginning of year	**$ 3**	$ 1	$ 1
Interest accrued during the year	**6**	2	—
Balance at end of year	**$ 9**	$ 3	$ 1

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

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 and 2014 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, reduced tax payments for 2015 and included in its 2013 and 2014 consolidated federal income tax returns deductions for R&E expenditures related to the Kemper IGCC. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures.

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. The IRS is currently reviewing the underlying support for the deduction, but has not completed its audit of these expenditures. Due to the uncertainty related to this tax position, the Company had related unrecognized tax benefits associated with these R&E deductions of approximately $423 million and associated interest of $9 million as of December 31, 2015. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC. The ultimate outcome of this matter cannot be determined at this time.

6. FINANCING

Bank Term Loans

In April 2015, the Company entered into two short-term floating rate bank loans with a maturity date of April 1, 2016 in an aggregate principal amount of $475 million bearing interest based on one-month LIBOR. The proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million , working capital, and other general corporate purposes, including the Company's ongoing construction program. The Company also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016.

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. At December 31, 2014, the Company had $775 million in bank loans outstanding which are classified as securities due within one year.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes 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, 2015 , the Company was in compliance with its debt limits.

Senior Notes

At December 31, 2015 and 2014 , the Company had $1.1 billion of senior notes outstanding. 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.

NOTES (continued)
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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, 2015 and 2014 was as follows:

	2015	2014
	(in millions)	
Senior notes	**$ 300**	$ —
Bank term loans	**425**	775
Capitalized leases	**3**	3
Outstanding at December 31	**$ 728**	$ 778

Maturities through 2020 applicable to total long-term debt are as follows: $728 million in 2016, $614 million in 2017, $3 million in 2018, $128 million in 2019, and $10 million in 2020.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2015 and 2014 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, 2015 and 2014 . 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, 2015 and 2014 of $77 million and $80 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 2015 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.

Other Obligations

In June 2015, the Company issued an 18 -month floating rate promissory note to Southern Company bearing interest based on LIBOR plus 1.25% . This note was for an aggregate principal amount of approximately $301 million , the amount paid by Southern Company to SMEPA pursuant to Southern Company's guarantee of the return of SMEPA's deposits. In December 2015, the $301 million promissory note was amended, which among other things, changed the maturity date to December 1, 2017 and changed the interest rate to be based on one-month LIBOR plus 1.50% . See Note 3 under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" for additional information.

In November 2015, the Company issued a 25 -month floating rate promissory note to Southern Company bearing interest based on an adjusted LIBOR rate. At December 31, 2015, the adjusted LIBOR rate was equal to the one-month LIBOR plus 1.50% . This note was for an aggregate principal amount of up to $375 million . As of December 31, 2015 the Company had borrowed $275 million .

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	$ 25	1,200,000	$ 25.00

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, 2015 , committed credit arrangements with banks were as follows:

Expires			Executable Term-Loans		Due Within One Year	
2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)	*(in millions)*		*(in millions)*		*(in millions)*	
$220	$220	$195	$30	$15	$45	$175

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration.

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 $195 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, 2015 was $40 million .

At December 31, 2015 and 2014 , there was no commercial paper debt outstanding.

At December 31, 2015, there was $500 million of short-term debt outstanding. At December 31, 2014, there was no short-term debt outstanding.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2015 , 2014 , and 2013 , the Company incurred fuel expense of $443 million , $574 million , and $491 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, 2015 of $38 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 operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $5 million , $10 million , and $10 million for 2015 , 2014 , and 2013 , 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 share (50%) of the leases, charged to fuel stock and recovered through the fuel cost recovery clause, was $2 million in 2015 , $3 million in 2014 , and $3 million in 2013 . The Company's annual railcar lease payments for 2016 through 2017 will average approximately $1 million . The Company has no lease obligations for the period 2018 and thereafter.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plants Daniel and Watson and operating leases for barges and tow/shift boats for the transport of coal at Plant Watson. The Company's share (50% at Plant Daniel and 100% at Plant Watson) of the leases for fuel handling was charged to fuel handling expense annually from 2013 through 2015 ; 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. The Company charged to fuel stock and recovered through fuel cost recovery the barge transportation leases in the amount of $2 million in 2015 , $8 million in 2014 , and $7 million in 2013 related to barges and tow/shift boats. The Company has no future lease commitments with respect to these barge transportation leases.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation, in the form of Southern Company stock options and 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, 2015 , there were 231 current and former employees participating in the stock option and performance share unit programs.

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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. As a result, stock-based compensation granted to employees in 2015 consisted exclusively of performance share units.

For the years ended December 31, 2014 and 2013 , employees of the Company were granted stock options for 578,256 shares and 345,830 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014 and 2013 derived using the Black-Scholes stock option pricing model was $2.20 and $2.93 , respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented. As of December 31, 2015 , 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, 2015 , 2014 , and 2013 was $3 million , $5 million , and $3 million , respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1 million , $2 million , and $1 million for the years ended December 31, 2015 , 2014 , and 2013 , respectively. As of December 31, 2015 , the aggregate intrinsic value for the options outstanding and options exercisable was $7 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 which equates to the requisite service period for accounting purposes. 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, issued in 2015, 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, 2015 , 2014 , and 2013 , employees of the Company were granted performance share units of 53,909 , 49,579 , and 36,769 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2015 , 2014 , and 2013 , 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 $46.41 , $37.54 , and $40.50 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2015 was $47.77 .

For the years ended December 31, 2015 , 2014 , and 2013 , total compensation cost for performance share units recognized in income was $4 million , $2 million , and $2 million , respectively, with the related tax benefit also recognized in income of $2 million , $1 million , and $1 million , respectively. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2015 , there was $1 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 19 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, 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

As of December 31, 2014 , 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, 2014:	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	$ 115	$ —	$ —	$ 115
Liabilities:				
Energy-related derivatives	$ —	$ 45	$ —	$ 45

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, 2015 and 2014 , 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:		
2015	**$ 2,537**	**$ 2,413**
2014	$ 2,320	$ 2,382

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 and occasionally foreign currency risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. 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 and the cash impacts of settled foreign currency derivatives are recorded as investing activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Mississippi PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

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, 2015 , the net volume of energy-related derivative contracts for natural gas positions totaled 32 million mmBtu for the Company, with the longest hedge date of 2018 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, 2015 , there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2016 are $1 million . The Company has deferred gains and losses that are expected to be amortized into earnings through 2022 .

Derivative Financial Statement Presentation and Amounts

At December 31, 2015 and 2014 , the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ —**	$ —	Other current liabilities	**$ 29**	$ 26
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**18**	19
Total derivatives designated as hedging instruments for regulatory purposes		**$ —**	$ —		**$ 47**	$ 45

Energy-related derivatives not designated as hedging instruments were immaterial for 2015 and 2014 .

The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. At December 31, 2015 and 2014 , energy-related derivatives presented in the table above did not have amounts available for offset.

At December 31, 2015 and 2014 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (29)**	$ (26)	Other regulatory liabilities, current	**$ —**	$ —
	Other regulatory assets, deferred	**(18)**	(19)	Other regulatory liabilities, deferred	**—**	—
Total energy-related derivative gains (losses)		**$ (47)**	$ (45)		**$ —**	$ —

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of operations were immaterial.

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of operations 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, 2015 , the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2015 , the fair value of derivative liabilities with contingent features was $12 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $52 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. 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 2015 and 2014 is as follows:

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) After Dividends on Preferred Stock
		(in millions)	
March 2015	**$ 276**	**$ 24**	**$ 35**
June 2015	**275**	**12**	**49**
September 2015	**341**	**(66)**	**(21)**
December 2015	**246**	**(143)**	**(71)**
March 2014	$ 331	$ (325)	$ (172)
June 2014	311	56	62
September 2014	355	(349)	(195)
December 2014	246	(71)	(24)

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 $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, and $380 million ($235 million after tax) in the first quarter 2014. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

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

SELECTED FINANCIAL AND OPERATING DATA 2011 - 2015
Mississippi Power Company 2015 Annual Report

	2015	2014	2013	2012	2011
Operating Revenues (in millions)	**$ 1,138**	$ 1,243	$ 1,145	$ 1,036	$ 1,113
Net Loss After Dividends on Preferred Stock (in millions)	**$ (8)**	$ (329)	$ (477)	$ 100	$ 94
Cash Dividends on Common Stock (in millions)	**$ —**	$ —	$ 72	$ 107	$ 76
Return on Average Common Equity (percent)	**(0.34)**	(15.43)	(24.28)	7.14	10.54
Total Assets (in millions) [(a)(b)]	**$ 7,840**	$ 6,642	$ 5,822	$ 5,334	$ 3,631
Gross Property Additions (in millions)	**$ 972**	$ 1,389	$ 1,773	$ 1,665	$ 1,206
Capitalization (in millions):					
Common stock equity	**$ 2,359**	$ 2,084	$ 2,177	$ 1,749	$ 1,049
Redeemable preferred stock	**33**	33	33	33	33
Long-term debt [(a)]	**1,886**	1,621	2,157	1,561	1,096
Total (excluding amounts due within one year)	**$ 4,278**	$ 3,738	$ 4,367	$ 3,343	$ 2,178
Capitalization Ratios (percent):					
Common stock equity	**55.1**	55.8	49.9	52.3	48.2
Redeemable preferred stock	**0.8**	0.9	0.7	1.0	1.5
Long-term debt [(a)]	**44.1**	43.3	49.4	46.7	50.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**153,158**	152,453	152,585	152,265	151,805
Commercial	**33,663**	33,496	33,250	33,112	33,200
Industrial	**467**	482	480	472	496
Other	**175**	175	175	175	175
Total	**187,463**	186,606	186,490	186,024	185,676
Employees (year-end)	**1,478**	1,478	1,344	1,281	1,264

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $9 million, $11 million, $4 million, and $8 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-03. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(b) A reclassification of deferred tax assets from Total Assets of $105 million, $16 million, $36 million, and $34 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-17. See Note 1 under "Recently Issued Accounting Standards" for additional information.

SELECTED FINANCIAL AND OPERATING DATA 2011 - 2015 (continued)
Mississippi Power Company 2015 Annual Report

	2015	2014	2013	2012	2011
Operating Revenues (in millions):					
Residential	**$ 238**	$ 239	$ 242	$ 227	$ 247
Commercial	**256**	257	266	251	263
Industrial	**287**	291	289	263	276
Other	**(5)**	8	2	6	7
Total retail	**776**	795	799	747	793
Wholesale — non-affiliates	**270**	323	294	256	273
Wholesale — affiliates	**76**	107	35	16	30
Total revenues from sales of electricity	**1,122**	1,225	1,128	1,019	1,096
Other revenues	**16**	18	17	17	17
Total	**$ 1,138**	$ 1,243	$ 1,145	$ 1,036	$ 1,113
Kilowatt-Hour Sales (in millions):					
Residential	**2,025**	2,126	2,088	2,046	2,162
Commercial	**2,806**	2,860	2,865	2,916	2,871
Industrial	**4,958**	4,943	4,739	4,702	4,586
Other	**40**	40	40	38	39
Total retail	**9,829**	9,969	9,732	9,702	9,658
Wholesale — non-affiliates	**3,852**	4,191	3,929	3,819	4,010
Wholesale — affiliates	**2,807**	2,900	931	572	649
Total	**16,488**	17,060	14,592	14,093	14,317
Average Revenue Per Kilowatt-Hour (cents) [(a)] :					
Residential	**11.75**	11.26	11.59	11.09	11.40
Commercial	**9.12**	8.99	9.27	8.60	9.17
Industrial	**5.79**	5.89	6.10	5.59	6.01
Total retail	**7.90**	7.97	8.21	7.70	8.21
Wholesale	**5.20**	6.06	6.76	6.19	6.52
Total sales	**6.80**	7.18	7.73	7.23	7.66
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,242**	13,934	13,680	13,426	14,229
Residential Average Annual Revenue Per Customer	**$ 1,556**	$ 1,568	$ 1,585	$ 1,489	$ 1,622
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**3,561**	3,867	3,088	3,088	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,548**	2,618	2,083	2,168	2,618
Summer	**2,403**	2,345	2,352	2,435	2,462
Annual Load Factor (percent)	**60.6**	59.4	64.7	61.9	59.1
Plant Availability Fossil-Steam (percent) [(b)]	**90.6**	87.6	89.3	91.5	87.7
Source of Energy Supply (percent):					
Coal	**16.5**	39.7	32.7	22.8	34.9
Oil and gas	**81.6**	55.3	57.1	63.9	51.5
Purchased power —					
From non-affiliates	**0.4**	1.4	2.0	2.0	1.4
From affiliates	**1.5**	3.6	8.2	11.3	12.2
Total	**100.0**	100.0	100.0	100.0	100.0

(a) The average revenue per kilowatt-hour (cents) is based on booked operating revenues and will not match billed revenue per kilowatt-hour.

(b) Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

SOUTHERN POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Power Company and Subsidiary Companies 2015 Annual Report

The management of Southern Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (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, 2015 .

/s/ Oscar C. Harper, IV
Oscar C. Harper, IV
President and Chief Executive Officer

/s/ William C. Grantham
William C. Grantham
Vice President, Chief Financial Officer, and Treasurer

February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Southern Power Company

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2015 and 2014 , and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2015 . 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 consolidated financial statements (pages II-473 to II-500) present fairly, in all material respects, the financial position of Southern Power Company and Subsidiary Companies as of December 31, 2015 and 2014 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 , in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 26, 2016

DEFINITIONS

Term	Meaning
Alabama Power	Alabama Power Company
AOCI	Accumulated other comprehensive income
ASC	Accounting Standards Codification
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
COD	Commercial operation date
CWIP	Construction work in progress
EMC	Electric Membership Corporation
EPA	U.S. Environmental Protection Agency
EPE	El Paso Electric Company
FERC	Federal Energy Regulatory Commission
First Solar	First Solar, Inc.
FPL	Florida Power & Light Company
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
MWH	Megawatt hour
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
SCE	Southern California Edison Company
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power Company, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
SRE	Southern Renewable Energy, Inc.
SRP	Southern Renewable Partnerships, LLC
STR	Southern Turner Renewable Energy, LLC owned 90% by SRE and 10% by TRE
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
TRE	Turner Renewable Energy, LLC, a 10% partner with SRE

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Power Company and Subsidiary Companies 2015 Annual Report

OVERVIEW

Business Activities

Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. The Company continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions and sales of assets, construction of new power plants, and entry into PPAs primarily with investor-owned utilities, independent power producers, municipalities, and electric cooperatives. In general, the Company has constructed or acquired new generating capacity only after entering into long-term PPAs for the new facilities.

During 2015, the Company acquired, constructed, or commenced construction of approximately 1,682 MWs of additional solar and wind facilities including six solar projects located in Georgia, six solar projects located in California, one solar project located in Texas, and one wind project located in Oklahoma. The Company also entered into an agreement to acquire an approximately 151-MW wind facility located in Oklahoma, contingent upon achieving certain construction and project milestones. In addition, a 20-MW solar facility located in California was acquired on February 11, 2016. See FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" herein for additional information.

As of December 31, 2015 , the Company owned generating units totaling 9,595 MWs of nameplate capacity in commercial operation, after taking into consideration its equity ownership percentage of the solar facilities. The average remaining duration of the Company's total portfolio of wholesale contracts is approximately 10 years, including the Company's renewable assets (biomass, solar, and wind), which have average contract coverage of approximately 21 years. The duration of these contracts reduces remarketing risk for the Company. With the inclusion of the PPAs and capacity associated with the solar facilities currently under construction and the acquisitions of Calipatria Solar, LLC (Calipatria), which was acquired after December 31, 2015, and Grant Wind, LLC (Grant Wind), which is expected to close in March 2016, as well as other capacity and energy contracts, the Company has an average of 75% of its available demonstrated capacity covered for the next five years (through 2020) and an average of 70% of its available demonstrated capacity covered for the next 10 years (through 2025). The Company's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets as well as the ability to execute its acquisition and growth strategy. See FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" herein for additional information.

Key Performance Indicators

To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company continues to focus on several key performance indicators, including peak season equivalent forced outage rate (Peak Season EFOR) and contract availability. Peak Season EFOR defines the hours during peak demand times when the Company's generating units are not available due to forced outages (a low metric is optimal). Contract availability measures the percentage of scheduled hours delivered. The Company's actual performance in 2015 met or surpassed targets in these two key performance areas.

Net income is the primary measure of the Company's financial performance. See RESULTS OF OPERATIONS herein for information on the Company's net income for 2015 .

Earnings

The Company's 2015 net income was $215 million , a $43 million, or 25%, increase from 2014 . The increase was primarily due to increased revenues from new PPAs, including solar and wind, partially offset by increased depreciation and other operations and maintenance expenses primarily due to new solar and wind facilities and higher income taxes.

The Company's 2014 net income was $172 million , a $6 million, or 4%, increase from 2013 . The increase was primarily due to a decrease in income taxes primarily as a result of federal ITCs for new plants placed in service in 2014 and an increase in energy revenue primarily related to new solar PPAs. This increase was partially offset by increased depreciation, other operations and maintenance expenses, and interest expense.

Benefits from ITCs related to the Company's acquisition and construction of solar facilities significantly impacted the Company's net income in 2015, 2014, and 2013. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2015 Annual Report

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2015	**2015**	2014
		(in millions)	
Operating revenues	**$ 1,390**	**$ (111)**	$ 226
Fuel	**441**	**(155)**	122
Purchased power	**93**	**(78)**	65
Other operations and maintenance	**260**	**23**	28
Depreciation and amortization	**248**	**28**	45
Taxes other than income taxes	**22**	**—**	1
Total operating expenses	**1,064**	**(182)**	261
Operating income	**326**	**71**	(35)
Interest expense, net of amounts capitalized	**77**	**(12)**	15
Other income (expense), net	**1**	**(5)**	10
Income taxes (benefit)	**21**	**24**	(49)
Net income	**229**	**54**	9
Less: Net income attributable to noncontrolling interests	**14**	**11**	3
Net income attributable to the Company	**$ 215**	**$ 43**	$ 6

Operating Revenues

PPA capacity revenues are derived primarily from long-term contracts involving natural gas and biomass generating facilities, and PPA energy revenues include sales from natural gas, biomass, solar, and wind facilities. To the extent the Company has unused capacity, it may sell power into the wholesale market or into the power pool.

	2015	2014	2013
		(in millions)	
PPA capacity revenues	**$ 569**	$ 546	$ 572
PPA energy revenues	**560**	638	451
Total PPA revenues	**1,129**	1,184	1,023
Revenues not covered by PPA	**252**	315	246
Other revenues	**9**	2	6
Total Operating Revenues	**$ 1,390**	$ 1,501	$ 1,275

Operating revenues for 2015 were $1.4 billion , reflecting a $111 million , or 7%, decrease from 2014 . The decrease in operating revenues was primarily due to the following:

- *PPA capacity revenues* increased $23 million ($50 million related to affiliates partially offset by $27 million related to non-affiliates), primarily due to a 1% increase in total MW capacity contracted associated with new natural gas PPAs.
- *PPA energy revenues* decreased $78 million due to a $141 million decrease primarily related to a 34% decrease in the average price of energy driven by lower natural gas prices passed through in fuel revenues, partially offset by a 13% increase in KWH sales. In addition, the decrease was partially offset by a $63 million increase in energy revenues from PPAs related to the Company's acquisitions of solar and wind facilities. Overall, total KWH sales under PPAs increased 15% in 2015 when compared to 2014.
- *Revenues not covered by PPA* decreased $63 million primarily due to lower natural gas prices, partially offset by a 19% increase in non-PPA KWH sales.

Operating revenues in 2014 were $1.5 billion, reflecting a $226 million, or 18%, increase from 2013 . The increase in operating revenues was primarily due to the following:

- *PPA capacity revenues* decreased $26 million primarily due to a 4% decrease in total MW capacity contracted associated with contract expirations.
- *PPA energy revenues* increased $187 million due to a $133 million increase primarily related to higher natural gas prices passed through in fuel revenues and a 27% increase in KWH sales. Also contributing to the increase was a $54 million increase in energy revenues related to the Company's acquisitions of solar facilities.
- *Revenues not covered by PPA* increased $69 million primarily due to a 9% increase in non-PPA KWH sales and higher gas prices.

Wholesale revenues will vary depending on the energy demand of the Company's customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of the Company's energy. Increases and decreases in revenues under PPAs 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.

Capacity revenues are an integral component of the Company's natural gas and biomass PPAs and generally represent the greatest contribution to net income. Energy under the PPAs is generally sold at variable cost or is indexed to published gas indices. Energy revenues also include fees for support services, fuel storage, and unit start charges.

See FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" herein for additional information regarding the Company's PPAs.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. Additionally, the Company purchases a portion of its electricity needs from the wholesale market. Details of the Company's generation and purchased power were as follows:

	Total KWHs	**Total KWH % Change**	Total KWHs	Total KWH % Change
	2015		2014	
	(in billions)		*(in billions)*	
Generation	**33**		27	
Purchased power	**2**		3	
Total generation and purchased power	**35**	**17%**	30	24%
Total generation and purchased power (excluding solar, wind and tolling)	**21**	**5%**	20	9%

The Company's PPAs for natural gas and biomass generation generally provide that the purchasers are responsible for either procuring the fuel (tolling agreements) or reimbursing the Company for substantially all of the cost of fuel relating to the energy delivered under such PPAs. Consequently, any increase or decrease in such fuel costs is generally accompanied by an increase or decrease in related fuel revenues under the PPAs and does not have a significant impact on net income. The Company is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the wholesale market or into the power pool, for capacity owned directly by the Company (excluding its subsidiaries).

Purchased power expenses will vary depending on demand and the availability and cost of generating resources throughout the Southern Company system and other contract resources. Load requirements are submitted to the power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by the Company, affiliate companies, or external parties.

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

	2015	2014	2013
		(in millions)	
Fuel	**$ 441**	$ 596	$ 474
Purchased power	**93**	171	106
Total fuel and purchased power expenses	**$ 534**	$ 767	$ 580

In 2015 , total fuel and purchased power expenses decreased $233 million, or 30%, compared to 2014 . The decrease was primarily due to the following:

- *Fuel expense* decreased $155 million, or 26%, primarily due to a $228 million decrease associated with the average cost of natural gas per KWH generated, partially offset by a $73 million increase associated with the volume of KWHs generated.
- *Purchased power expense* decreased $78 million, or 46%, primarily due to a $60 million decrease associated with the volume of KWHs purchased as well as an $18 million decrease associated with the average cost of purchased power.

In 2014 , total fuel and purchased power expenses increased $187 million, or 32%, compared to 2013 . The increase was primarily due to the following:

- *Fuel expense* increased $122 million, or 26%, primarily due to a $91 million increase associated with the average cost of natural gas per KWH generated as well as a $31 million increase associated with the volume of KWHs generated.
- *Purchased power expense* increased $65 million, or 61%, primarily due to a $33 million increase associated with the average cost of purchased power and a $32 million increase associated with the volume of KWHs purchased.

Other Operations and Maintenance Expenses

In 2015 , other operations and maintenance expenses increased $23 million, or 10%, compared to 2014 . The increase was primarily due to increases of $11 million associated with new plants placed in service in 2014 and 2015, $10 million in business development and support services expenses, $5 million in transmission costs, and $3 million in employee compensation. These increases were partially offset by a $6 million decrease in generation maintenance expense.

In 2014 , other operations and maintenance expenses increased $29 million, or 14%, compared to 2013 . The increase was primarily due to an $11 million increase in other generation expenses primarily related to labor and repairs as well as an $8 million increase primarily as a result of increased business development costs and support services. Also contributing to the increase was a $7 million increase in costs related to new plants placed in service, and a $2 million increase in employee compensation.

Depreciation and Amortization

In 2015 , depreciation and amortization increased $28 million, or 13%, compared to 2014 . The increase was primarily related to new plants placed in service in 2014 and 2015.

In 2014 , depreciation and amortization increased $45 million, or 26%, compared to 2013 . The increase resulted primarily from $25 million associated with an increase in plant in service, $8 million related to equipment retirements resulting from accelerated outage work, and $6 million related to increased production at natural gas plants.

See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Depreciation" herein for additional information regarding the Company's ongoing review of depreciation estimates and change to component depreciation in 2014. See also Note 1 to the financial statements under "Depreciation" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2015 , interest expense, net of amounts capitalized decreased $12 million, or 13%, compared to 2014 . The decrease was primarily due to a $14 million increase in capitalized interest associated with the construction of solar facilities, partially offset by an increase of $2 million in interest expense related to additional debt issued to fund the Company's growth strategy and continuous construction program.

In 2014 , interest expense, net of amounts capitalized increased $15 million, or 20%, compared to 2013 . The increase was primarily due to a $9 million decrease in capitalized interest resulting from the completion of Plants Spectrum and Campo Verde in 2013 and an increase of $5 million in interest expense related to senior notes.

Other Income (Expense), Net

In 2015 , other income (expense), net decreased $5 million compared to 2014 , which increased $10 million compared to 2013 . These changes were driven by the recognition of a $5 million bargain purchase gain recognized in 2014 arising from a solar acquisition. Additionally, in 2013 net income attributable to noncontrolling interests of approximately $4 million was included in other income (expense), net. See Note 10 to the financial statements for additional information on noncontrolling interests.

Income Taxes (Benefit)

In 2015 , income taxes (benefit) increased $24 million compared to 2014 . The increase was primarily due to a $26 million increase associated with higher pre-tax earnings and a $9 million increase resulting from state apportionment rate changes, partially offset by an $11 million increase in federal income tax benefits primarily related to ITCs for solar plants placed in service in 2015 .

In 2014 , income taxes (benefit) decreased $49 million compared to 2013 . The decrease was primarily due to a $20 million increase in tax benefits primarily from federal ITCs for solar plants placed in service in 2014, a $20 million decrease associated with lower pre-tax earnings, and an $11 million reduction in deferred income taxes as a result of the impact of state apportionment changes and beneficial changes in certain state income tax laws.

See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The results of operations for the past three years are not necessarily indicative of the Company's future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's competitive wholesale business. These factors include: the Company's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in the Company's market areas; the successful remarketing of capacity as current contracts expire; and the Company's ability to execute its growth strategy, including successfully expanding investments in renewable and other energy projects, and to construct generating facilities, including the impact of ITCs. Demand for electricity is partially 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.

Other factors that could influence future earnings include weather, demand, cost of generating units within the power pool, and operational limitations.

Power Sales Agreements

General

The Company has assumed or entered into PPAs with some of Southern Company's traditional operating companies, other investor owned utilities, independent power producers, municipalities, electric cooperatives, and other load serving entities. Although some of the Company's PPAs are with the traditional operating companies or other regulated utilities, the Company's generating facilities are not in those companies' regulated rate bases and the Company is not able to seek recovery from those companies' ratepayers for construction, repair, environmental compliance, or maintenance costs. The Company expects that the capacity payments in the Company's PPAs involving natural gas and biomass generating facilities will produce sufficient cash flows to cover such costs, pay debt service, and provide an equity return. However, the Company's overall profit will depend on numerous factors, including efficient operation of its generating facilities and demand under the Company's PPAs. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

Many of the Company's PPAs have provisions that require the Company or the counterparty to post collateral or an acceptable substitute guarantee in the event that S&P or Moody's downgrades the credit ratings of the respective company to an unacceptable credit rating or if the counterparty is not rated or fails to maintain a minimum coverage ratio.

The Company is working to maintain and expand its share of the wholesale market. The Company expects that additional demand for capacity will begin to develop within some of its market areas in the 2016-2018 timeframe. With the inclusion of the PPAs and capacity associated with the solar facilities currently under construction, and the acquisitions of Calipatria, which was acquired after December 31, 2015, and Grant Wind, which is expected to close in March 2016, as well as other capacity and energy contracts, the Company has an average of 75% of its available demonstrated capacity covered for the next five years (through 2020) and an average of 70% of its available demonstrated capacity covered for the next 10 years (through 2025). See "Acquisitions" and "Construction Projects" herein for additional information.

Natural Gas and Biomass

The Company's electricity sales from natural gas and biomass generating units are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated generating unit where all or a portion of the generation from that unit is reserved for that customer. The Company typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that the Company serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Company resources not dedicated to serve unit or block sales. The Company has rights to purchase power provided by the requirements customers' resources when economically viable.

As a general matter, substantially all of the PPAs provide that the purchasers are responsible for either procuring the fuel or reimbursing the Company for the cost of fuel relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for transporting the fuel to the particular generating facility.

Capacity charges that form part of the PPA payments are designed to recover fixed and variable operation and maintenance costs based on dollars-per-kilowatt year. In general, to reduce the Company's exposure to certain operation and maintenance costs, the Company has long-term service agreements (LTSA). See Note 1 to the financial statements under "Long-Term Service Agreements" for additional information.

Solar and Wind

The Company's electricity sales from solar and wind generating facilities are also through long-term PPAs, but do not have a capacity charge. Instead, the customers purchase the energy output of a dedicated renewable facility through an energy charge. As a result, the Company's ability to recover fixed and variable operation and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance and other factors.

Environmental Matters

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and state regulations. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, water quality, or other environmental and health concerns could also significantly affect the Company.

New environmental legislation or regulations, such as requirements related to greenhouse gases or changes to existing statutes or regulations, could affect many areas of the Company's operations. While the Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Since the Company's units are newer natural gas and renewable generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal or older natural gas generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the potential presence of wetlands or threatened and endangered species, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts can, however, increase the cost of siting and operating any type of future electric generating facility. The impact of such statutes and regulations on the Company cannot be determined at this time.

Environmental Statutes and Regulations

Air Quality

Each of the states in which the Company has fossil generation is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I having begun in 2015 and Phase II beginning in 2017. On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Alabama, Florida, Georgia, North Carolina, and Texas, but rejected all other pending challenges to the rule. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. On December 3, 2015, the EPA published a proposed revision to CSAPR that would revise existing ozone-season emissions budgets for nitrogen oxide in Alabama and would remove Florida from the CSAPR program. The EPA proposes to finalize this rulemaking by summer 2016.

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

On June 12, 2015, the EPA published a final rule requiring certain states (including Alabama, Florida, Georgia, North Carolina, and Texas) to revise or remove the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM) by no later than November 22, 2016.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. The impacts of CSAPR, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in additional capital expenditures and compliance costs that could affect results of operations, cash flows, and financial condition if such costs are not recovered through PPAs. Further, if higher costs are recovered through regulated rates at other utilities, this could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

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 October 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

On November 3, 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 National Pollutant Discharge Elimination System 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. The ultimate impact of these requirements will depend on pending and any future legal challenges, compliance dates, and implementation of the final rule and cannot be determined at this time.

These water quality regulations could result in additional capital expenditures and compliance costs. Also, results of operations, cash flows, and financial condition could be impacted if such costs are not recovered through PPAs. Based on a preliminary assessment of the impact of the proposed rules, the Company estimates compliance costs to be immaterial. Further, if higher costs are recovered through regulated rates at other utilities, this could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Global Climate Issues

On October 23, 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 its review with the courts. The stay will remain in effect through the resolution of the litigation, whether resolved in the U.S. Court of Appeals for the District of Columbia Circuit or 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. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through PPAs. Further, if higher costs are recovered through regulated rates at other utilities, this could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. 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 Company's ongoing review of the final rules; the outcome of legal challenges, individual state implementation of the EPA's final guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

The United Nations 21 st international climate change conference took place in late 2015. The result was the adoption of 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 increasing those commitments every five years. The ultimate impact of this agreement depends on its ratification and implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2014 greenhouse gas emissions were approximately 11 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2015 greenhouse gas emissions on the same basis is approximately 13 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.

Income Tax Matters

Tax Credits

In 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. The PATH Act extended the ITC with a phase out that allows for 30% ITC for solar projects that commence construction by December 31, 2019; 26% ITC for solar projects that commence construction in 2020; 22% ITC for solar projects that commence construction in 2021; and the permanent 10% ITC for solar projects that commence construction on or after January 1, 2022. In addition, the PATH Act extended the production tax credit (PTC) for wind projects with a phase out that allows for 100% PTC for wind projects that commence construction in 2016; 80% PTC for wind projects that commence construction in 2017; 60% PTC for wind projects that commence construction in 2018; and 40% PTC for wind projects that commence construction in 2019. The Company receives ITCs related to new solar facilities and receives PTCs related to energy production from its wind facility, which have had and will continue to have a material impact on cash flows and net income. See Note 1 to the financial statements under "Income and Other Taxes" and Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Bonus Depreciation

The PATH Act also extended bonus depreciation for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 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 50% bonus depreciation is expected to result in approximately $195 million of positive cash flows for the 2015 tax year and approximately $350 million for the 2016 tax year, which may not all be realized in 2016 due to a projected net operating loss for tax purposes on the Company's 2016 income tax return because of bonus depreciation. The ultimate outcome of this matter cannot be determined at this time

Acquisitions

During 2015, in accordance with the Company's overall growth strategy, the Company acquired or contracted to acquire through its wholly-owned subsidiaries, SRP or SRE, the projects set forth in the following table. Acquisition-related costs were expensed as incurred and are discussed in the Company's "RESULTS OF OPERATIONS" herein, if significant. See Note 2 to the financial statements for additional information.

Project Facility	Approx. Nameplate Capacity	Location	Percentage Ownership		Expected/Actual COD	PPA Contract Period
	(MW)					
WIND						
Kay Wind	299	Kay County, OK	100%		December 12, 2015	20 years
Grant Wind [(c)]	151	Grant County, OK	100%		March 2016	20 years
SOLAR						
Lost Hills Blackwell	33	Kern County, CA	51%	(a)	April 17, 2015	29 years
North Star	61	Fresno County, CA	51%	(a)	June 20, 2015	20 years
Tranquillity [(d)]	205	Fresno County, CA	51%	(a)	Fourth quarter 2016	18 years
Desert Stateline [(e)]	299	San Bernardino County, CA	51%	(a)	December 2015 to third quarter 2016 [(f)]	20 years
Morelos	15	Kern County, CA	90%	(b)	November 25, 2015	20 years
Roserock [(g)]	160	Pecos County, TX	51%	(a)	Fourth quarter 2016	20 years
Garland and Garland A [(h)]	205	Kern County, CA	51%	(a)	Fourth quarter 2016	15 years and 20 years
Calipatria [(i)]	20	Imperial County, CA	90%	(b)	February 11, 2016	20 years

(a) The Company owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. The Company and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to the transaction.

(b) The Company owns 90%, with the minority owner, TRE, owning 10%.

(c) ***Grant Wind*** - On September 4, 2015, the Company entered into an agreement to acquire Grant Wind, LLC. The completion of the acquisition is subject to the seller achieving certain construction and project milestones as well as various other customary conditions to closing. The acquisition is expected to close at or near the expected COD. The ultimate outcome of this matter cannot be determined at this time.

(d) ***Tranquillity*** - Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $473 million to $493 million . The ultimate outcome of this matter cannot be determined at this time.

(e) ***Desert Stateline*** - Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $1.2 billion to $1.3 billion . The ultimate outcome of this matter cannot be determined at this time.

(f) ***Desert Stateline*** - The first three of eight phases were placed in service in December 2015. Subsequent to December 31, 2015, phases four and five were placed in service.

(g) ***Roserock*** - Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $333 million to $353 million . The ultimate outcome of this matter cannot be determined at this time.

(h) ***Garland and Garland A*** - Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $532 million to $552 million . The ultimate outcome of this matter cannot be determined at this time.

(i) ***Calipatria*** - On February 11, 2016, SRE and TRE acquired all of the outstanding membership interests of Calipatria.

The aggregate amount of revenue recognized by the Company related to the acquisitions, since the various acquisition dates, included in the consolidated statement of income for 2015 is $18 million . The aggregate amount of net income, excluding the impacts of ITCs, attributable to the Company related to the acquisitions, since the various acquisition dates, included in the consolidated statement of income is immaterial. These businesses did not have operating revenues or activities prior to their assets being constructed and placed in service; therefore, supplemental proforma information as though the acquisitions occurred as of the beginning of 2015 and for the comparable 2014 year is not meaningful and has been omitted.

Construction Projects

During 2015, in accordance with the Company's overall growth strategy, the Company constructed or commenced construction of the projects set forth in the table below, in addition to the Tranquillity, Desert Stateline, Roserock, Garland, and Garland A facilities. Total cost of construction incurred for these projects during 2015 was $ 1.8 billion , of which $1.1 billion remains in CWIP at December 31, 2015 . The ultimate outcome of these matters cannot be determined at this time.

Solar Facility	Approx. Nameplate Capacity	County Location in Georgia	Expected/Actual COD	PPA Contract Period	Estimated Construction Cost	
	(MW)				(in millions)	
Sandhills	146	Taylor	Fourth quarter 2016	25 years	$ 260 - 280	
Decatur Parkway	84	Decatur	December 31, 2015	25 years	Approx. $169	(*)
Decatur County	20	Decatur	December 29, 2015	20 years	Approx. $46	(*)
Butler	103	Taylor	Fourth quarter 2016	30 years	$ 220 - 230	(*)
Pawpaw	30	Taylor	March 2016	30 years	$ 70 - 80	(*)
Butler Solar Farm	22	Taylor	February 10, 2016	20 years	Approx. $45	(*)

(*) Includes the acquisition price of all outstanding membership interests of the respective development entity.

FERC Matters

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 operating companies and the Company filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' and the Company's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. The FERC directed the traditional operating companies and the Company 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 operating companies and the Company filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. 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 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.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Revenue Recognition

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with GAAP. In general, the Company's power sale transactions can be classified in one of four categories: leases, non-derivatives or normal sale derivatives, derivatives designated as cash flow hedges, and derivatives not designated as hedges. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 9 to the financial statements. The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract.

Lease Transactions

The Company considers the following factors to determine whether the sales contract is a lease:

- Assessing whether specific property is explicitly or implicitly identified in the agreement;
- Determining whether the fulfillment of the arrangement is dependent on the use of the identified property; and
- Assessing whether the arrangement conveys to the purchaser the right to use the identified property.

If the contract meets the above criteria for a lease, the Company performs further analysis as to whether the lease is classified as operating, financing, or sales-type. All of the Company's power sales contracts classified as leases are accounted for as operating leases and the capacity revenue is recognized on a straight-line basis over the term of the contract and are included in the Company's operating revenues. Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. All revenues under solar and wind PPAs are accounted for as contingent revenues and recognized as services are performed.

Non-Derivative and Normal Sale Derivative Transactions

If the power sales contract is not classified as a lease, the Company further considers the following factors to determine proper classification:

- Assessing whether the contract meets the definition of a derivative;
- Assessing whether the contract meets the definition of a capacity contract;
- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery; and
- Ensuring that the contract quantities do not exceed available generating capacity (including purchased capacity).

Contracts that do not meet the definition of a derivative or are designated as normal sales (i.e. capacity contracts which provide for the sale of electricity that involve physical delivery in quantities within the Company's available generating capacity) are accounted for as executory contracts. The related capacity revenue is recognized on an accrual basis in amounts equal to the lesser of the cumulative levelized amount or the cumulative amount billable under the contract over the respective contract periods. Energy revenues are recognized in the period the energy is delivered or the service is rendered. Contracts recorded on the accrual basis represented the majority of the Company's operating revenues.

Cash Flow Hedge Transactions

The Company further considers the following in designating other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions:

- Identifying the hedging instrument, the hedged transaction, and the nature of the risk being hedged; and
- Assessing hedge effectiveness at inception and throughout the contract term.

These contracts are accounted for on a fair value basis and are recorded in AOCI over the life of the contract. Realized gains and losses are then recognized in operating revenues as incurred.

Mark-to-Market Transactions

Contracts for sales of electricity, which meet the definition of a derivative and that either do not qualify or are not designated as normal sales or as cash flow hedges, are accounted for on a fair value basis and are recorded in operating revenues.

Impairment of Long-Lived Assets and Intangibles

The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company's intangible assets have arisen from certain acquisitions and consist of acquired PPAs that are amortized over the term of the respective PPAs and goodwill. The Company evaluates the carrying value of these assets in accordance with accounting standards whenever indicators of potential impairment exist, or annually in the case of goodwill. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses or a projection of continuing losses, a significant decrease in market prices, and the inability to remarket generating capacity for an extended period. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:

- Future demand for electricity based on projections of economic growth and estimates of available generating capacity;
- Future power and natural gas prices, which have been quite volatile in recent years; and
- Future operating costs.

Acquisition Accounting

The Company acquires generation assets as part of its overall growth strategy. For acquisitions that meet the definition of a business, the Company includes the operations in its consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition is allocated based on the fair value of the identifiable assets and liabilities. Assets acquired that do not meet the definition of a business are accounted for as asset acquisitions. The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions are expensed as incurred.

Depreciation

Beginning in 2014, the Company changed to component depreciation, where the depreciation of the original cost of assets is computed principally by the straight-line method over the estimated useful lives of assets determined by management. Certain generation assets are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. The primary assets in property, plant, and equipment are power plants, which have estimated useful lives ranging from 30 to 45 years. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes that could have a material impact on net income in the near term.

When property subject to depreciation is retired or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

Prior to 2014, the Company computed depreciation on the original cost of assets under the straight-line method and applied a composite depreciation rate based on the assets' estimated useful lives determined by management.

Investment Tax Credits

Under current tax legislation, certain construction costs related to renewable generating assets are eligible for federal ITCs. A high degree of judgment is required in determining which construction expenditures qualify for federal ITCs. See Note 1 to the financial statements under "Income and Other Taxes" for additional information.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers* (ASC 606) , revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On February 18, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis* (ASU 2015-02), which makes certain changes to both the variable interest model and the voting model, including changes to the identification of variable interests, the variable interest entity characteristics for a limited partnership or similar entity, and the primary beneficiary determination. ASU 2015-02 is effective for fiscal years beginning after December 15, 2015 and is not expected to result in any additional consolidation or deconsolidation of current entities.

On April 7, 2015, the FASB issued ASU No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03) . ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $11 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 8 to the financial statements for disclosures impacted by ASU 2015-03.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from deferred income taxes, current of $306 million and accrued income taxes of $2 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 to the financial statements for disclosures impacted by ASU 2015-17.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2015 . The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements as needed to meet its future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $1.0 billion in 2015 , an increase of $400 million compared to 2014 . This increase was primarily due to an increase in income tax benefits received and increased revenues from new PPAs, including solar PPAs. Net cash provided from operating activities totaled $603 million in 2014 and $ 604 million in 2013 .

Net cash used for investing activities totaled $2.5 billion , $814 million , and $696 million in 2015 , 2014 , and 2013 , respectively. Net cash used for investing activities in 2015 , 2014 , and 2013 was primarily due to acquisitions and the construction of renewable facilities.

Net cash provided from financing activities totaled $2.3 billion , $217 million , and $132 million in 2015 , 2014 , and 2013 , respectively. Net cash provided from financing activities in 2015 was primarily due to the issuance of additional senior notes and a 13-month bank loan. Net cash provided from financing activities in 2014 was primarily due to the issuance of commercial paper. Net cash provided from financing activities in 2013 was primarily the result of the issuance of new senior notes.

As of December 31, 2015, the Company had $551 million of unutilized ITCs which are not expected to be fully utilized until 2020, primarily due to the extension of bonus depreciation.

Significant asset changes in the balance sheet during 2015 included an increase in cash, CWIP, plant in service, and other intangible assets, primarily due to the acquisition and construction of renewable facilities.

Significant liability and stockholder's equity changes in the balance sheet during 2015 included an increase in long-term debt primarily as a result of the issuance of senior notes, an increase in accounts payable related to construction and an increase in noncontrolling interests primarily due to contributions made by class B members for their portion of the related acquisitions.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, securities issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

With respect to the public offering of securities, the Company (excluding its subsidiaries) files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amount of securities registered under the 1933 Act is continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

As of December 31, 2015 , the Company's current liabilities exceeded current assets by $131 million due to long-term debt maturing in 2016, the use of short-term debt as a funding source, and construction payables, as well as cash needs, which can fluctuate significantly due to the seasonality of the business and the stage of its acquisitions and construction projects. In 2016, the Company expects to utilize the capital markets, bank term loans, and commercial paper markets as the source of funds for the majority of its maturities.

To meet liquidity and capital resource requirements, the Company had at December 31, 2015 cash and cash equivalents of approximately $830 million .

Company Facility

At December 31, 2015 , the Company (excluding its subsidiaries) had a committed credit facility of $600 million (Facility). In August 2015, the Company amended and restated the Facility, which, among other things, extended the maturity date from 2018 to 2020 and increased its borrowing ability to $600 million from $500 million. As of December 31, 2015 , the total amount available under the Facility was $566 million.

The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% and contains a cross default provision that is restricted only to indebtedness of the Company. For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of the Company to the extent such debt is non-recourse to the Company, and capitalization excludes the capital stock or other equity attributable to such subsidiary. The Company is currently in compliance with all covenants in the Facility.

Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. Subject to applicable market conditions, the Company expects to renew or replace the Facility, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitment thereunder. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Subsidiary Facilities

In connection with the construction of solar facilities by RE Tranquillity LLC, RE Roserock LLC, and RE Garland Holdings LLC, indirect subsidiaries of the Company, each subsidiary entered into separate credit agreements (Project Credit Facilities), which are non-recourse to the Company (other than the subsidiary party to the agreement). Each Project Credit Facility provides (a) a senior secured construction loan credit facility, (b) a senior secured bridge loan facility, and (c) a senior secured letter of credit facility that is secured by the membership interests of the respective project company. Proceeds from the Project Credit Facilities are being used to finance project costs related to the respective solar facilities currently under construction. Each Project Credit Facility is secured by the assets of the applicable project subsidiary and membership interests of the applicable project subsidiary. The table below summarizes each Project Credit Facility as of December 31, 2015 .

Project	Maturity Date	Construction Loan Facility	Bridge Loan Facility	Total	Total Undrawn	Letter of Credit Facility	Total Undrawn
					(in millions)		
Tranquillity	Earlier of COD or December 31, 2016	$ 86	$ 172	$ 258	$ 147	$ 77	$ 26
Roserock	Earlier of COD or November 30, 2016	63	180	243	243	23	23
Garland	Earlier of COD or November 30, 2016	86	308	394	368	49	32
Total		$ 235	$ 660	$ 895	$ 758	$ 149	$ 81

The Project Credit Facilities had total amounts outstanding as of December 31, 2015 in notes payable of $137 million at a weighted average interest rate of 2.0%. For the year ended December 31, 2015 , these credit agreements had a maximum amount outstanding of $137 million , and an average amount outstanding of $13 million at a weighted average interest rate of 2.0%.

Commercial Paper Program

The Company's commercial paper program (excluding its subsidiaries) is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes, including maturing debt. Commercial paper was used to partially fund the maturity of long-term debt in July 2015.

Details of short-term borrowings (commercial paper) were as follows:

	Commercial Paper at the End of the Period		Commercial Paper During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2015	**$ —**	**N/A**	**$ 166**	**0.5%**	**$ 385**
December 31, 2014	$ 195	0.4%	$ 54	0.4%	$ 445
December 31, 2013	$ —	N/A	$ 117	0.4%	$ 271

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2015 , 2014 , and 2013 .

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, the Facility, bank term loans, and operating cash flows.

Financing Activities

Senior Notes

In May 2015, the Company issued $350 million aggregate principal amount of Series 2015A 1.500% Senior Notes due June 1, 2018 and $300 million aggregate principal amount of Series 2015B 2.375% Senior Notes due June 1, 2020. The proceeds were used to repay a portion of its outstanding short-term indebtedness, for other general corporate purposes, including the Company's growth strategy and continuous construction program, and for a portion of the repayment at maturity of $525 million aggregate principal amount of the Company's 4.875% Senior Notes on July 15, 2015.

In November 2015, the Company issued $500 million aggregate principal amount of Series 2015C 4.15% Senior Notes due December 1, 2025 and $500 million aggregate principal amount of Series 2015D 1.85% Senior Notes due December 1, 2017. The proceeds will be allocated to funding renewable energy generation projects.

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

Other Debt

In August 2015, the Company (excluding its subsidiaries) entered into a $400 million aggregate principal amount 13-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes, including the Company's growth strategy and continuous construction program.

During 2015 , the Company prepaid $4 million of long-term debt to TRE.

Subsidiary Project Credit Facilities

Subsequent to December 31, 2015, the Company borrowed $182 million pursuant to the Project Credit Facilities at a weighted average interest rate of 2.0%. In addition, the Company issued $8 million in letters of credit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, energy price risk management, and transmission.

The maximum potential collateral requirements under these contracts at December 31, 2015 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and/or Baa2	$ 11
At BBB- and/or Baa3	$ 338
Below BBB- and/or Baa3	$ 1,070

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

In addition, the Company has a PPA that could require collateral, but not accelerated payment, in the event of a downgrade of the Company's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade.

On August 24, 2015, S&P revised its credit rating outlook from stable to negative following the announcement of the proposed merger of a wholly-owned direct subsidiary of Southern Company with and into AGL Resources Inc.

Market Price Risk

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

At December 31, 2015 , the Company had $13 million of long-term variable rate notes outstanding. The effect on annualized interest expense related to variable interest rate exposure if the Company sustained a 100 basis point change in interest rates is immaterial. Since a significant portion of outstanding indebtedness bears interest at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot be determined at this time.

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

The fair value and changes in fair value of energy-related derivative contracts associated with both power and natural gas positions were immaterial as of December 31, 2015 and 2014.

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

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 8 to the financial statements for further discussion of fair value measurements. The energy-related derivative contracts outstanding at December 31, 2015 were immaterial and all mature by 2017.

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 S&P and Moody's 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. See Note 1 to the financial statements under "Financial Instruments" and Note 9 to the financial statements for additional information.

Capital Requirements and Contractual Obligations

The capital program of the Company is currently estimated to total $2.4 billion for 2016 , $1.0 billion for 2017 , and $1.5 billion for 2018 . The construction program is subject to periodic review and revision. These amounts include estimates for potential plant acquisitions and new construction. In addition, the construction program includes capital improvements and work to be performed under LTSAs. Planned expenditures for plant acquisitions may vary materially due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of numerous factors such as: changes in business conditions; changes in the expected environmental compliance program; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in FERC rules and regulations; changes in load projections; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. See Note 2 to the financial statements under "Acquisitions" for additional information.

In addition, TRE can require the Company to purchase its redeemable noncontrolling interests in STR, which owns various solar facilities contracted under long-term PPAs, at fair market value pursuant to the partnership agreement. At December 31, 2015 , the redeemable noncontrolling interests was $43 million.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, unrecognized tax benefits, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 5, 6, 7, and 9 to the financial statements for additional information.

Contractual Obligations

	2016	2017-2018	2019-2020	After 2020	Total
			(in millions)		
Long-term debt [(a)] —					
Principal	$ 403	$ 850	$ 300	$ 1,588	$ 3,141
Interest	104	189	169	1,280	1,742
Financial derivative obligations [(b)]	3	—	—	—	3
Operating leases [(c)]	11	24	25	595	655
Unrecognized tax benefits [(d)]	8	—	—	—	8
Purchase commitments —					
Capital [(e)]	2,304	2,385	—	—	4,689
Fuel [(f)]	309	530	432	121	1,392
Purchased power [(g)]	38	79	82	42	241
Other [(h)]	107	276	183	785	1,351
Transmission agreements [(i)]	10	18	16	18	62
Total	$ 3,297	$ 4,351	$ 1,207	$ 4,429	$ 13,284

(a) All amounts are reflected based on final maturity dates. 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.

(b) For additional information, see Notes 1 and 9 to the financial statements.

(c) Operating lease commitments include certain land leases that are subject to annual price escalation based on indices.

(d) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures associated with environmental regulations. Amounts represent current estimates of total expenditures, excluding capital expenditures covered under LTSAs. See Note (h) below.

(f) Primarily includes commitments to purchase, transport, and store natural gas fuel. Amounts reflected are based on contracted cost and may contain provisions for price escalation. Amounts reflected for natural gas purchase commitments are based on various indices at the time of delivery and have been estimated based on the New York Mercantile Exchange future prices at December 31, 2015 .

(g) Purchased power commitments will be resold under a third party agreement at cost.

(h) Includes LTSA and operation and maintenance agreements. LTSAs include price escalation based on inflation indices.

(i) Transmission commitments are based on Southern Company's current tariff rate for point-to-point transmission.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2015 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the Company's business, customer growth, economic recovery, fuel and environmental cost recovery , current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, financing activities, estimated sales and purchases under power sale and purchase agreements, timing of expected future capacity need in existing markets, completion of acquisitions and construction projects, filings with federal regulatory authorities, impact of the PATH Act, 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 legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, 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, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including , without limitation, IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the 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 and construction of generating facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards , including the requirements of tax credits and other incentives ;
- advances in technology;
- state and federal rate regulations ;
- the ability to successfully operate generating facilities and the successful performance of necessary corporate functions;
- 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 ongoing partnerships with TRE, First Solar, and Recurrent;
- 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 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, 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.

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2015 , 2014 , and 2013
Southern Power Company and Subsidiary Companies 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Revenues:			
Wholesale revenues, non-affiliates	**$ 964**	$ 1,116	$ 923
Wholesale revenues, affiliates	**417**	383	346
Other revenues	**9**	2	6
Total operating revenues	**1,390**	1,501	1,275
Operating Expenses:			
Fuel	**441**	596	474
Purchased power, non-affiliates	**72**	105	76
Purchased power, affiliates	**21**	66	30
Other operations and maintenance	**260**	237	209
Depreciation and amortization	**248**	220	175
Taxes other than income taxes	**22**	22	21
Total operating expenses	**1,064**	1,246	985
Operating Income	**326**	255	290
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(77)**	(89)	(74)
Other income (expense), net	**1**	6	(4)
Total other income and (expense)	**(76)**	(83)	(78)
Earnings Before Income Taxes	**250**	172	212
Income taxes (benefit)	**21**	(3)	46
Net Income	**229**	175	166
Less: Net income attributable to noncontrolling interests	**14**	3	—
Net Income Attributable to the Company	**$ 215**	$ 172	$ 166

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2015 , 2014 , and 2013
Southern Power Company and Subsidiary Companies 2015 Annual Report

	2015	2014	2013
		(in millions)	
Net Income	**$ 229**	$ 175	$ 166
Other comprehensive income (loss):			
Qualifying hedges:			
Reclassification adjustment for amounts included in net income, net of tax of $-, $-, and $2, respectively	**1**	—	4
Total other comprehensive income	**1**	—	4
Less: Comprehensive income attributable to noncontrolling interests	**14**	3	—
Comprehensive Income Attributable to the Company	**$ 216**	$ 172	$ 170

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2015 , 2014 , and 2013
Southern Power Company and Subsidiary Companies 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Activities:			
Net income	**$ 229**	$ 175	$ 166
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization	**254**	225	183
Deferred income taxes	**42**	(168)	171
Investment tax credits	**162**	74	158
Amortization of investment tax credits	**(19)**	(11)	(6)
Deferred revenues	**(15)**	(21)	(18)
Accrued income taxes, non-current	**109**	—	—
Other, net	**13**	11	4
Changes in certain current assets and liabilities —			
-Receivables	**18**	(26)	(11)
-Prepaid income taxes	**(26)**	35	(30)
-Other current assets	**(4)**	(8)	(8)
-Accounts payable	**(19)**	30	(12)
-Accrued taxes	**269**	284	—
-Other current liabilities	**(10)**	3	7
Net cash provided from operating activities	**1,003**	603	604
Investing Activities:			
Plant acquisitions	**(1,719)**	(731)	(132)
Property additions	**(1,005)**	(21)	(501)
Change in construction payables	**251**	—	(4)
Investment in restricted cash	**(159)**	—	—
Distribution of restricted cash	**154**	—	—
Payments pursuant to long-term service agreements	**(82)**	(61)	(57)
Other investing activities	**22**	(1)	(2)
Net cash used for investing activities	**(2,538)**	(814)	(696)
Financing Activities:			
Increase (decrease) in notes payable, net	**(58)**	195	(71)
Proceeds —			
Capital contributions	**646**	146	1
Senior notes	**1,650**	—	300
Other long-term debt	**402**	10	24
Redemptions —			
Senior notes	**(525)**	—	—
Other long-term debt	**(4)**	(10)	(9)
Distributions to noncontrolling interests	**(18)**	(1)	(1)
Capital contributions from noncontrolling interests	**341**	8	17
Payment of common stock dividends	**(131)**	(131)	(129)
Other financing activities	**(13)**	—	—
Net cash provided from financing activities	**2,290**	217	132
Net Change in Cash and Cash Equivalents	**755**	6	40
Cash and Cash Equivalents at Beginning of Year	**75**	69	29
Cash and Cash Equivalents at End of Year	**$ 830**	$ 75	$ 69
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $14, $-, and $9 capitalized, respectively)	**$ 74**	$ 85	$ 60

Income taxes (net of refunds and investment tax credits)	**(518)**	(220)	(226)
Noncash transactions —			
Accrued property additions at year-end	**257**	1	6
Acquisitions	**—**	229	—
Capital contributions from noncontrolling interests	**—**	221	—

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2015 and 2014
Southern Power Company and Subsidiary Companies 2015 Annual Report

Assets	**2015**	2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 830**	$ 75
Receivables —		
Customer accounts receivable	**75**	77
Other accounts receivable	**19**	15
Affiliated companies	**30**	34
Fossil fuel stock, at average cost	**16**	22
Materials and supplies, at average cost	**63**	58
Prepaid income taxes	**45**	19
Other prepaid expenses	**23**	17
Assets from risk management activities	**7**	5
Total current assets	**1,108**	322
Property, Plant, and Equipment:		
In service	**7,275**	5,657
Less accumulated provision for depreciation	**1,248**	1,035
Plant in service, net of depreciation	**6,027**	4,622
Construction work in progress	**1,137**	11
Total property, plant, and equipment	**7,164**	4,633
Other Property and Investments:		
Goodwill	**2**	2
Other intangible assets, net of amortization of $12 and $9 at December 31, 2015 and December 31, 2014, respectively	**317**	47
Total other property and investments	**319**	49
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	**166**	124
Other deferred charges and assets — affiliated	**9**	5
Other deferred charges and assets — non-affiliated	**139**	100
Total deferred charges and other assets	**314**	229
Total Assets	**$ 8,905**	$ 5,233

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2015 and 2014
Southern Power Company and Subsidiary Companies 2015 Annual Report

Liabilities and Stockholders' Equity	**2015**	2014
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 403**	$ 525
Notes payable	**137**	195
Accounts payable —		
Affiliated	**66**	78
Other	**327**	30
Accrued taxes —		
Accrued income taxes	**198**	70
Other accrued taxes	**5**	3
Accrued interest	**23**	30
Contingent consideration	**36**	8
Other current liabilities	**44**	6
Total current liabilities	**1,239**	945
Long-Term Debt:		
Senior notes —		
1.85% due 2017	**500**	—
1.50% due 2018	**350**	—
2.375% due 2020	**300**	—
4.15% to 6.375% due 2025-2043	**1,575**	1,075
Other long-term notes — variable rate (3.50% at 1/1/16) due 2032-2035	**13**	19
Unamortized debt premium (discount), net	**—**	2
Unamortized debt issuance expense	**(19)**	(11)
Long-term debt	**2,719**	1,085
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**601**	559
Accumulated deferred investment tax credits	**889**	601
Accrued income taxes, non-current	**109**	—
Asset retirement obligations	**21**	13
Deferred capacity revenues — affiliated	**17**	15
Other deferred credits and liabilities	**3**	5
Total deferred credits and other liabilities	**1,640**	1,193
Total Liabilities	**5,598**	3,223
Redeemable Noncontrolling Interests	**43**	39
Common Stockholder's Equity:		
Common stock, par value $0.01 per share —		
Authorized — 1,000,000 shares		
Outstanding — 1,000 shares	**—**	—
Paid-in capital	**1,822**	1,176
Retained earnings	**657**	573
Accumulated other comprehensive income	**4**	3
Total common stockholder's equity	**2,483**	1,752
Noncontrolling Interests	**781**	219
Total Stockholders' Equity	**3,264**	1,971
Total Liabilities and Stockholders' Equity	**$ 8,905**	$ 5,233
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2015 , 2014 , and 2013
Southern Power Company and Subsidiary Companies 2015 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity	Noncontrolling Interests	Total
					(in millions)			
Balance at December 31, 2012	—	$ —	$ 1,028	$ 495	$ (1)	$ 1,522	$ —	$ 1,522
Net income attributable to the Company	—	—	—	166	—	166	—	166
Capital contributions from parent company	—	—	1	—	—	1	—	1
Other comprehensive income	—	—	—	—	4	4	—	4
Cash dividends on common stock	—	—	—	(129)	—	(129)	—	(129)
Balance at December 31, 2013	—	—	1,029	532	3	1,564	—	1,564
Net income attributable to the Company	—	—	—	172	—	172	—	172
Capital contributions from parent company	—	—	147	—	—	147	—	147
Cash dividends on common stock	—	—	—	(131)	—	(131)	—	(131)
Capital contributions from noncontrolling interests	—	—	—	—	—	—	221	221
Net loss attributable to noncontrolling interests	—	—	—	—	—	—	(2)	(2)
Balance at December 31, 2014	**—**	**—**	**1,176**	**573**	**3**	**1,752**	**219**	**1,971**
Net income attributable to the Company	**—**	**—**	**—**	**215**	**—**	**215**	**—**	**215**
Capital contributions from parent company	**—**	**—**	**646**	**—**	**—**	**646**	**—**	**646**
Other comprehensive income	**—**	**—**	**—**	**—**	**1**	**1**	**—**	**1**
Cash dividends on common stock	**—**	**—**	**—**	**(131)**	**—**	**(131)**	**—**	**(131)**
Capital contributions from noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**567**	**567**
Distributions to noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(17)**	**(17)**
Net income attributable to noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**12**	**12**
Balance at December 31, 2015	**—**	**$ —**	**$ 1,822**	**$ 657**	**$ 4**	**$ 2,483**	**$ 781**	**$ 3,264**

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

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NOTES (continued)
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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Power Company is a wholly-owned subsidiary of Southern Company, which is also the parent company of four traditional operating companies, SCS, SouthernLINC Wireless, and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast.

Southern Power Company and certain of its generation subsidiaries are subject to regulation by the FERC. The preparation of consolidated 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 consolidated financial statements have been reclassified to conform to the current year presentation.

The consolidated financial statements include the accounts of Southern Power Company and its wholly-owned and majority-owned subsidiaries. Intercompany accounts and transactions have been eliminated in consolidation.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers* (ASC 606) *,* revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On February 18, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis* (ASU 2015-02), which makes certain changes to both the variable interest model and the voting model, including changes to the identification of variable interests, the variable interest entity characteristics for a limited partnership or similar entity, and the primary beneficiary determination. ASU 2015-02 is effective for fiscal years beginning after December 15, 2015 and is not expected to result in any additional consolidation or deconsolidation of current entities.

On April 7, 2015, the FASB issued ASU No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03) . ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $11 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 8 for disclosures impacted by ASU 2015-03.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from deferred income taxes, current of $306 million and accrued income taxes of $2 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 for disclosures impacted by ASU 2015-17.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at amounts in compliance with FERC regulation: general and design engineering, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, labor, and other services with respect to business and operations, construction management, and transactions associated with the Southern Company system's fleet of generating units. Because the Company has no employees, all employee-related charges are rendered at amounts in compliance with FERC regulation under agreements with SCS. Costs for all of these services from SCS amounted to approximately $146 million in 2015 , $126 million in 2014 , and $118 million in 2013 . Of these costs, approximately $138 million in 2015 , $125 million in 2014 , and $114 million in 2013 were charged to other operations and maintenance expenses; the remainder was capitalized to property, plant, and equipment. 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 several agreements with SCS for transmission services. Transmission purchased from affiliates totaled $11 million in 2015 , $7 million in 2014 , and $8 million in 2013 . All charges were billed to the Company based on the Southern Company Open Access Transmission Tariff as filed with the FERC.

Total revenues from all PPAs with affiliates, included in wholesale revenue affiliates on the consolidated statements of income, were $219 million , $153 million , and $150 million in 2015 , 2014 , and 2013 , respectively. Included within these revenues were affiliate PPAs accounted for as operating leases, which totaled $109 million , $75 million , and $69 million in 2015 , 2014 , and 2013 , respectively.

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

The Company and the traditional operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

Acquisition Accounting

The Company acquires generation assets as part of its overall growth strategy. For acquisitions that meet the definition of a business, the Company includes the operations in its consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition is allocated based on the fair value of the identifiable assets and liabilities. Assets acquired that do not meet the definition of a business are accounted for as asset acquisitions. The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions are expensed as incurred.

Revenues

The Company sells capacity at rates specified under contractual terms for long-term PPAs. These PPAs are generally accounted for as operating leases, non-derivatives, or normal sale derivatives. Capacity revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Capacity revenues from PPAs classified as non-derivatives or normal sales are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods. When multiple contracts exist with the same counterparty, the revenues from each contract are accounted for as separate arrangements. All capacity revenues are included in operating revenues.

The Company may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains (losses) on such contracts are recorded in wholesale revenues. See Note 9 for additional information.

Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. All revenues under solar PPAs are accounted for as contingent revenues and recognized as services are performed. Transmission revenues and other fees are recognized as earned as other operating revenues. See "Financial Instruments" herein for additional information.

Significant portions of the Company's revenues have been derived from certain customers pursuant to PPAs. The following table shows the percentage of total revenues for the top three customers:

	2015	2014	2013
Georgia Power	**15.8%**	10.1%	11.8%
FPL	**10.7%**	9.7%	10.7%
Duke Energy Corporation	**8.2%**	9.1%	10.3%

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel costs also include emissions allowances which are expensed as the emissions occur.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences.

Under current tax regulation, certain projects are eligible for federal ITCs. The Company estimates eligible costs which, as they relate to acquisitions, may not be finalized until the allocation of the purchase price to assets has been finalized. The credits are recorded as a deferred credit and are amortized to income tax expense over the life of the asset. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a net deferred tax asset. The Company has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. In addition, certain projects are eligible for federal production tax credits (PTC), which are recorded to income tax expense based on production. Federal ITCs and PTCs available to reduce income taxes payable were not fully utilized during the year and will be carried forward and utilized in future years. The ITC carryforwards begin expiring in 2034, but are expected to be fully utilized by 2020. See Note 5 under "Effective Tax Rate" for additional information.

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

The Company's depreciable property, plant, and equipment consists primarily of generation assets.

Property, plant, and equipment is stated at original cost. Original cost includes: materials, direct labor incurred by contractors and affiliated companies, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred.

Depreciation

Beginning in 2014, the Company changed to component depreciation, where the depreciation of the original cost of assets is computed principally by the straight-line method over the estimated useful lives of assets as determined by management. Certain generation assets are now depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. The primary assets in property, plant, and equipment are power plants, which have estimated useful lives ranging from 30 to 45 years . The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term. Plant in service as of December 31, 2015 and 2014 that is depreciated on a units-of-production basis was approximately $485 million and $470 million , respectively.

When property subject to depreciation is retired or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

Prior to 2014, the Company computed depreciation of the original cost of assets under the straight-line method and applied a composite depreciation rate based on the assets' estimated useful lives as determined by management.

Asset Retirement Obligations

Asset retirement obligations (ARO) 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.

The liability for AROs primarily relates to the Company's solar and wind facilities.

NOTES (continued)
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Details of the AROs included in the balance sheets are as follows:

	2015	2014
	(in millions)	
Balance at beginning of year	$ 13	$ 4
Liabilities incurred	7	8
Accretion	1	1
Balance at end of year	$ 21	$ 13

Long-Term Service Agreements

The Company has entered into LTSAs for the purpose of securing maintenance support for substantially all of its generating facilities. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

Payments made under the LTSAs prior to the performance of any planned inspections or unplanned capital maintenance are recorded as a prepayment in noncurrent assets on the balance sheets and are recorded as payments pursuant to LTSAs in the statements of cash flows. All work performed is capitalized or charged to expense as appropriate based on the nature of the work when performed; therefore, these charges are non-cash and are not reflected in the statements of cash flows.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets and finite-lived intangibles for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company's intangible assets consist of acquired PPAs that are amortized over the term of the PPA and goodwill resulting from acquisitions. The average term of these PPAs is 20 years . The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

The amortization expense for the acquired PPAs for each of the years ended December 31, 2015 , 2014 , and 2013 was $3 million , and is recorded in operating revenues. The amortization expense for future periods is as follows:

	Amortization Expense
	(in millions)
2016	$ 10
2017	17
2018	17
2019	17
2020	17
2021 and beyond	239
Total	$ 317

Transmission Receivables/Prepayments

As part of the Company's growth through the acquisition and construction of renewable facilities, the Company has transmission receivables and/or prepayments representing the reimbursable portion of interconnection network and transmission upgrades that will be reimbursed to the Company. Upon completion of the related project, transmission costs are generally reimbursed by the interconnection provider within a five -year period and the receivable/prepayments are reduced as payments or services are received.

Emission Reduction Credits

The Company has acquired emission reduction credits necessary for future unspecified construction in areas designated by the EPA as non-attainment areas for nitrogen oxide or volatile organic compound emissions. These credits are reflected on the balance sheets at historical cost and were $11 million at each of December 31, 2015 and 2014 . The cost of emission reduction offsets to be surrendered are generally transferred to CWIP upon commencement of the related construction.

Restricted Cash

The use of funds received under the credit facilities of RE Tranquillity LLC, RE Roserock LLC, and RE Garland Holdings LLC are restricted for construction purposes. The aggregate amount outstanding as of December 31, 2015 was $5 million and is included in other deferred charges and assets — non-affiliated.

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 generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the cost of oil, natural gas, biomass, and emissions allowances. The Company maintains oil inventory for use at several generating units. The Company has contracts in place for natural gas storage to support normal operations of the Company's natural gas generating units. The Company maintains biomass inventory for use at Plant Nacogdoches. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used. Emissions allowances granted by the EPA are included at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 8 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 fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions result in the deferral of related gains and losses in AOCI until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded in the financial statement line item where they will eventually settle. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 9 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2015 .

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 of 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 has certain wholly-owned subsidiaries that are determined to be VIEs. The Company is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests.

2. ACQUISITIONS

During 2015 and 2014, in accordance with the Company's overall growth strategy, the Company acquired or contracted to acquire through its wholly-owned subsidiaries, SRP or SRE, the projects set forth in the following table. Acquisition-related costs of approximately $4 million were expensed as incurred. The acquisitions do not include any contingent consideration unless specifically noted.

NOTES (continued)
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2015

Project Facility	Seller; Acquisition Date	Approx. Nameplate Capacity	Location	Percentage Ownership		Expected/Actual COD	PPA Counterparties for Plant Output	PPA Contract Period	Approx. Purchase Price	
		(MW)							*(in millions)*	
WIND										
Kay Wind	Apex Clean Energy Holdings, LLC December 11, 2015	299	Kay County, OK	100%		December 12, 2015	Westar Energy, Inc. and Grant River Dam Authority	20 years	$ 481	(b)
Grant Wind	Apex Clean Energy Holdings, LLC	151	Grant County, OK	100%		March 2016	Western Farmers, East Texas, and Northeast Texas Electric Cooperative	20 years	$ 258	(c)
SOLAR										
Lost Hills Blackwell	First Solar April 15, 2015	33	Kern County, CA	51%	(a)	April 17, 2015	City of Roseville, California/Pacific Gas and Electric Company	29 years	$ 73	(d)
North Star	First Solar April 30, 2015	61	Fresno County, CA	51%	(a)	June 20, 2015	Pacific Gas and Electric Company	20 years	$ 208	(e)
Tranquillity	Recurrent Energy, LLC August 28, 2015	205	Fresno County, CA	51%	(a)	Fourth quarter 2016	Shell Energy North America (US), LP and then SCE	18 years	$ 100	(f)
Desert Stateline	First Solar August 31, 2015	299	San Bernardino County, CA	51%	(a)	From December 2015 to third quarter 2016 (h)	SCE	20 years	$ 439	(g)
Morelos	Solar Frontier Americas Holding, LLC October 22, 2015	15	Kern County, CA	90%		November 25, 2015	Pacific Gas and Electric Company	20 years	$ 45	(i)
Roserock	Recurrent Energy, LLC November 23, 2015	160	Pecos County, TX	51%	(a)	Fourth quarter 2016	Austin Energy	20 years	$ 45	(j)
Garland and Garland A	Recurrent Energy, LLC December 17, 2015	205	Kern County, CA	51%	(a)	Fourth quarter 2016	SCE	15 years and 20 years	$ 49	(k)
Calipatria	Solar Frontier Americas Holding, LLC February 11, 2016	20	Imperial County, CA	90%		February 11, 2016	San Diego Gas & Electric Company	20 years	$ 52	(l)

(a) The Company owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. The Company and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to the transaction. At each acquisition, the Company acquired a controlling interest in the entity owning the project facility and recorded approximately $227 million for the noncontrolling interests, in the aggregate, which is recorded as a non-cash transaction in contributions from noncontrolling interests and plant acquisitions.

(b) ***Kay Wind*** - The total purchase price, including $35 million of contingent consideration, is approximately $481 million . As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $481 million as CWIP, $8 million as a receivable related to transmission interconnection costs, and $8 million as payables; however, the allocation of the purchase price to individual assets has not been finalized.

(c) ***Grant Wind*** - On September 4, 2015, Southern Power entered into an agreement to acquire Grant Wind, LLC. The completion of the acquisition is subject to the seller achieving certain construction and project milestones as well as various other customary conditions to closing. The acquisition is expected to close at or near the expected COD. The purchase price includes approximately $24 million of contingent consideration and may be adjusted based on performance testing and production over the first 10 years of operation. The ultimate outcome of this matter cannot be determined at this time.

(d) ***Lost Hills Blackwell*** - Concurrent with the acquisition, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests for approximately $34 million . At the acquisition date, the members became contingently obligated to pay $3 million of construction payables through COD, making the aggregate purchase price approximately $107 million . The fair values of the assets acquired through the business combination were recorded as follows: $105 million as property, plant, and equipment, $3 million as a receivable related to transmission interconnection costs, and $4 million as construction and other payables; however, the allocation of the purchase price to individual assets has not been finalized.

(e) ***North Star*** - Concurrent with the acquisition, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests for approximately $99 million . At the acquisition date, the members became contingently obligated to pay $233 million of construction payables through COD, making the aggregate purchase price approximately $307 million . The fair values of the assets acquired through the business combination were recorded as follows: $266 million as property, plant, and equipment, $25 million as an intangible asset, $21 million as a receivable related to transmission interconnection costs, and $238 million as construction and other payables; however, the allocation of the purchase price to individual assets has not been finalized. The intangible asset consists of an acquired PPA that will be amortized over its 20 -year term. The amortization expense for the year ended December 31, 2015 was $1 million . The estimated amortization for future periods is approximately $1.2 million per year for 2016 through 2020, and $18 million thereafter.

(f) ***Tranquillity*** - Concurrent with the acquisition, a wholly-owned subsidiary of Recurrent Energy, LLC converted all its membership interests to 100% of the class B membership interests after contributing approximately $173 million of assets and receiving an initial distribution of $100 million . As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $186 million as CWIP, $24 million as other receivables, and $37 million as payables; however, the allocation of the purchase price to individual assets has not been finalized. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $473 million to $493 million . The ultimate outcome of this matter cannot be determined at this time.

(g) ***Desert Stateline*** - Concurrent with the acquisition, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests for approximately $223 million . As of December 31, 2015, the fair values of the assets acquired through the business combination, which includes the Company's and First Solar's initial payments due under the related construction agreement, were recorded as follows: $413 million as CWIP and $249 million as an intangible asset; however, the allocation of the purchase price to individual assets has not been finalized. The intangible asset consists of an acquired PPA that will be amortized over its 20 -year term. The estimated amortization for future periods is approximately $6.2 million in 2016, $12.5 million per year for 2017 through 2020, and $192.8 million thereafter. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $1.2 billion to $1.3 billion . The ultimate outcome of this matter cannot be determined at this time.

(h) ***Desert Stateline*** - The first three of eight phases were placed in service in December 2015. Subsequent to December 31, 2015, phases four and five were placed in service.

(i) ***Morelos*** - The total purchase price, including the minority owner, TRE's 10% ownership interest, is approximately $50 million . As of December 31, 2015, the fair values of the assets acquired through the business combination were recorded as follows: $49 million as property, plant, and equipment and $1 million as a receivable related to transmission interconnection costs; however, the allocation of the purchase price to individual assets has not been finalized.

(j) ***Roserock*** - Concurrent with the acquisition, a wholly-owned subsidiary of Recurrent Energy, LLC converted all its membership interests to 100% of the class B membership interests after contributing approximately $26 million of assets. As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $75 million as CWIP, $6 million as other receivables, and $10 million as payables and accrued expenses; however, the allocation of the purchase price to individual assets has not been finalized. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $333 million to $353 million . The ultimate outcome of this matter cannot be determined at this time.

(k) ***Garland and Garland A*** - Concurrent with the acquisition, a wholly-owned subsidiary of Recurrent Energy, LLC converted all its membership interests to 100% of the class B membership interests after contributing approximately $31 million of assets. As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $107 million as CWIP, $1 million as other deferred assets, and $28 million as payables and other accrued expenses; however, the allocation of the purchase price to individual assets has not been finalized. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $532 million to $552 million . The ultimate outcome of this matter cannot be determined at this time.

(l) ***Calipatria*** - The total purchase price, including the minority owner, TRE's 10% ownership interest, is approximately $58 million .

The aggregate amount of revenue recognized by to the Company related to the acquisitions, since the various acquisition dates, included in the consolidated statement of income for 2015 is $18 million . The aggregate amount of net income, excluding the impacts of ITCs, attributable to the Company related to the acquisitions, since the various acquisition dates, included in the consolidated statement of income is immaterial. These businesses did not have operating revenues or activities prior to their assets being constructed and placed in service; and therefore, supplemental proforma information as though the acquisitions occurred as of the beginning of 2015, and for the comparable 2014 year is not meaningful and has been omitted.

2014

Project Facility	Seller; Acquisition Date	Approx. Nameplate Capacity	Location	Percentage Ownership		COD	PPA Counterparties for Plant Output	PPA Contract Period	Approx. Purchase Price	
		(MW)							*(in millions)*	
SOLAR										
Adobe	Sun Edison, LLC April 17, 2014	20	Kern County, CA	90%		May 21, 2014	SCE	20 years	$ 86	(b)
Macho Springs	First Solar Development, LLC May 22, 2014	50	Luna County, NM	90%		May 23, 2014	EPE	20 years	$ 117	(c)
Imperial Valley	First Solar, October 22, 2014	150	Imperial County, CA	51%	(a)	November 26, 2014	San Diego Gas & Electric Company	25 years	$ 505	(d)

(a) The Company owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. The Company and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to the transaction.

(b) ***Adobe*** - Total purchase price, including the minority owner TRE's 10% ownership interest, was $97 million . The fair values of the assets acquired were ultimately recorded as follows: $84 million to property, plant, and equipment, $15 million to prepayment related to transmission services, and $6 million to PPA intangible, resulting in a $5 million bargain purchase gain and a $3 million deferred tax liability. The bargain purchase gain is included in other income (expense), net. Acquisition-related costs were expensed as incurred and were not material.

(c) ***Macho Springs*** - Total purchase price, including the minority owner TRE's 10% ownership interest, was $130 million . The fair values of the assets acquired were ultimately recorded as follows: $128 million to property, plant, and equipment, $1 million to prepaid property taxes, and $1 million to prepayment related to transmission services. The acquisition did not include any contingent consideration. Acquisition-related costs were expensed as incurred and were not material.

(d) ***Imperial Valley*** - In connection with this acquisition, SG2 Holdings, LLC (SG2 Holdings) made an aggregate payment of approximately $128 million to a subsidiary of First Solar and became obligated to pay additional contingent consideration of approximately $599 million upon completion of the facility (representing the amount due to an affiliate of First Solar under the construction contract for Imperial Valley). When substantial completion was achieved in November 2014, a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The members of SG2 Holdings made additional agreed upon capital contributions totaling $593 million to SG2 Holdings that were used to pay the contingent consideration due, leaving $6.0 million of contingent consideration payable upon final acceptance of the facility. As a result of these capital contributions, the aggregate purchase price payable by the Company for the acquisition of Imperial Valley was approximately $505 million in addition to the $223 million noncash contribution by the minority member. The fair values of the assets acquired were ultimately recorded as follows: $708 million to property, plant, and equipment and $20 million to prepayment related to transmission services. Acquisition-related costs were expensed as incurred and were not material.

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Construction Projects

During 2015, in accordance with the Company's overall growth strategy, the Company constructed or commenced construction of the projects set forth in the table below, in addition to the Tranquillity, Desert Stateline, Roserock, Garland, and Garland A facilities. Total cost of construction incurred for these projects during 2015 was $1.8 billion , of which $1.1 billion remains in CWIP at December 31, 2015 .

Solar Facility	Seller	Approx. Nameplate Capacity	County Location in Georgia	Expected/Actual COD	PPA Counterparties for Plant Output	PPA Contract Period	Estimated Construction Cost	
		(MW)					*(in millions)*	
Sandhills	N/A	146	Taylor	Fourth quarter 2016	Cobb, Flint, and Sawnee EMCs	25 years	$ 260 - 280	
Decatur Parkway	TradeWind Energy, Inc.	84	Decatur	December 31, 2015	Georgia Power [(a)]	25 years	Approx. $169	[(c)]
Decatur County	TradeWind Energy, Inc.	20	Decatur	December 29, 2015	Georgia Power	20 years	Approx. $46	[(c)]
Butler	CERSM, LLC and Community Energy, Inc.	103	Taylor	Fourth quarter 2016	Georgia Power [(b)]	30 years	$ 220 - 230	[(c)]
Pawpaw	Longview Solar, LLC	30	Taylor	March 2016	Georgia Power [(a)]	30 years	$ 70 - 80	[(c)]
Butler Solar Farm	Strata Solar Development, LLC	22	Taylor	February 10, 2016	Georgia Power	20 years	Approx. $45	[(c)]

(a) Affiliate PPA approved by the FERC.

(b) Affiliate PPA subject to FERC approval.

(c) Includes the acquisition price of all outstanding membership interests of the respective development entity.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property 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 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 and its subsidiaries 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.

FERC Matters

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 operating companies and the Company filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' and the Company's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. The FERC directed the traditional operating companies and the Company 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 operating companies and the

Company filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

The Company is a 65% owner of Plant Stanton A, a combined-cycle project unit with a nameplate capacity of 659 MWs. The unit is co-owned by the Orlando Utilities Commission (28%), Florida Municipal Power Agency (3.5%), and Kissimmee Utility Authority (3.5%). The Company has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton A. As of December 31, 2015 , $157 million was recorded in plant in service with associated accumulated depreciation of $53 million . These amounts represent the Company's share of the total plant assets and each owner is responsible for providing its own financing. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined or unitary. 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:

	2015	2014	2013
		(in millions)	
Federal —			
Current (*)	**$ 12**	$ 179	$ (120)
Deferred (*)	**10**	(166)	159
	22	13	39
State —			
Current	**(32)**	(14)	(5)
Deferred	**31**	(2)	12
	(1)	(16)	7
Total	**$ 21**	$ (3)	$ 46

(*) ITCs generated in the current tax year and carried forward from prior tax years that cannot be utilized in the current tax year are reclassified from current to deferred taxes in the federal income tax expense above. ITCs reclassified in this manner include $246 million for 2015 and $305 million for 2014. These ITCs are included in the following table of temporary differences as unrealized tax credits.

NOTES (continued)
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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:

	2015	2014
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation and other property basis differences	**$ 1,364**	$ 1,006
Basis difference on asset transfers	**3**	3
Levelized capacity revenues	**22**	17
Other	**4**	6
Total	**1,393**	1,032
Deferred tax assets —		
Federal effect of state deferred taxes	**40**	29
Net basis difference on federal ITCs	**149**	102
Alternative minimum tax carryforward	**15**	15
Unrealized tax credits	**551**	305
Unrealized loss on interest rate swaps	**4**	6
Levelized capacity revenues	**4**	5
Deferred state tax assets	**13**	15
Other	**18**	4
Total	**794**	481
Valuation Allowance	**(2)**	(8)
Net deferred income tax assets	**792**	473
Accumulated deferred income taxes	**$ 601**	$ 559

On November 20, 2015, the FASB issued ASU 2015-17, which simplifies the presentation of deferred income taxes. The new guidance resulted in a reclassification from deferred income taxes, current of $306 million and accrued income taxes of $2 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Deferred tax liabilities are primarily the result of property related timing differences. The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation in 2015 and 2014.

Deferred tax assets consist primarily of timing differences related to net basis differences on federal ITCs and the carryforward of unrealized federal ITCs. The ITC carryforwards begin expiring in 2034, but are expected to be fully utilized by 2020.

At December 31, 2015 and December 31, 2014 , the Company had state net operating loss (NOL) carryforwards of $225 million and $247 million , respectively. The NOL carryforwards resulted in deferred tax assets of $8 million as of December 31, 2015 and $9 million as of December 31, 2014 . The Company has established a valuation allowance due to the remote likelihood that the full tax benefits will be realized. During 2015 , approximately $87 million in NOLs expired resulting in a decrease in the valuation allowance for the same amount. The offsetting adjustments resulted in no tax impact. Of the NOL balance at December 31, 2015 , approximately $40 million will expire in 2017 and $185 million will expire from 2033 to 2035.

NOTES (continued)
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Effective Tax Rate

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

	2015	2014	2013
Federal statutory rate	**35.0 %**	35.0 %	35.0 %
State income tax, net of federal deduction	**(0.3)**	(6.0)	2.2
Amortization of ITC	**(5.0)**	(4.3)	(1.7)
ITC basis difference	**(21.5)**	(27.7)	(14.5)
Other	**0.2**	1.1	0.3
Effective income tax rate	**8.4 %**	(1.9)%	21.3 %

The Company's effective tax rate increased in 2015 primarily due to decreased benefits from federal ITCs as compared to 2014. The Company's effective tax rate decreased in 2014 primarily due to greater benefits from federal ITCs as compared to 2013.

The Company received cash related to federal ITCs under the renewable energy initiatives of $162 million in tax year 2015 , $74 million in tax year 2014 , and $158 million in tax year 2013 . The tax benefit of the related basis difference reduced income tax expense by $54 million in 2015 , $48 million in 2014 , and $31 million in 2013 . Federal ITCs amortized to income tax expense amounted to $19 million , $11 million , and $6 million in 2015, 2014, and 2013, respectively.

See Note 1 under "Income and Other Taxes" for additional information.

Unrecognized Tax Benefits

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

	2015	2014	2013
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 5**	$ 2	$ 3
Tax positions increase from current periods	**9**	5	2
Tax positions decrease from prior periods	**(6)**	(2)	(3)
Balance at end of year	**$ 8**	$ 5	$ 2

The increase in unrecognized tax benefits from current periods for 2015 , 2014 and 2013 , and the decrease from prior periods in 2015 and 2014 primarily relate to federal ITCs and would each impact the Company's effective tax rate, if recognized. The decrease in unrecognized tax benefits from prior periods for 2013 relates to the Company's compliance with final U.S. Treasury regulations for the tax method change for repairs.

The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 and 2014 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.

6. FINANCING

Southern Power Company's senior notes and credit facility are unsecured senior debt securities, which rank equally with all other unsecured and unsubordinated debt of Southern Power Company. The senior notes and credit facility are subordinated to any future secured debt and any potential claims of creditors of Southern Power Company's subsidiaries. As of December 31, 2015 , the company had no secured debt at its subsidiaries other than the three secured project credit facilities, which are discussed below.

Securities Due Within One Year

At December 31, 2015 and 2014, the Company had a $400 million bank loan and $525 million of senior notes due within one year, respectively. In addition, at December 31, 2015 , the Company classified as due within one year approximately $3 million of long-term notes payable to TRE that are expected to be repaid in 2016.

Maturities through 2020 applicable to total long-term debt are as follows: $500 million in 2017, $350 million in 2018, and $300 million in 2020.

Other Long-Term Notes

During 2015 , the Company prepaid $4 million of long-term notes payable to TRE and issued $2 million due September 30, 2035 under a promissory note related to the financing of Morelos. At December 31, 2015 and 2014 , the Company had $13 million and $19 million , respectively, of long-term notes payable to TRE.

In August 2015, the Company entered into a $400 million aggregate principal amount 13 -month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes, including the Company's growth strategy and continuous construction program.

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 project debt incurred by certain subsidiaries of the Company to the extent such debt is non-recourse to the Company, and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2015 , the Company was in compliance with its debt limits.

Senior Notes

In May 2015, the Company issued $350 million aggregate principal amount of its Series 2015A 1.500% Senior Notes due June 1, 2018 and $300 million aggregate principal amount of Series 2015B 2.375% Senior Notes due June 1, 2020. The proceeds were used to repay a portion of its outstanding short-term indebtedness, for other general corporate purposes, including the Company’s growth strategy and continuous construction program, and for a portion of the repayment at maturity of $525 million aggregate principal amount of the Company's 4.875% Senior Notes on July 15, 2015.

In November 2015, the Company issued $500 million aggregate principal amount of its Series 2015C 4.15% Senior Notes due December 1, 2025 and $500 million aggregate principal amount of Series 2015D 1.85% Senior Notes due December 1, 2017. The proceeds will be used for renewable energy generation projects.

At December 31, 2015 and 2014 , the Company had $2.7 billion and $1.6 billion of senior notes outstanding, respectively, which included senior notes due within one year.

Bank Credit Arrangements

Company Facility

In August 2015, the Company amended and restated its multi-year credit facility (Facility). This amendment extended among other things the maturity date from 2018 to 2020. The Company also increased its borrowing ability under the Facility to $600 million from $500 million . As of December 31, 2015 , the total amount available under the Facility was $566 million . As of December 31, 2014 , the total amount available under the previous $500 million facility was $488 million . The amounts outstanding as of December 31, 2015 and 2014 reflect $34 million and $12 million in letters of credit, respectively. The Facility does not contain a material adverse change clause at the time of borrowing. Subject to applicable market conditions, the Company plans to renew or replace the Facility prior to expiration.

The Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than 1/4 of 1%. The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% . For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of the Company to the extent such debt is non-recourse to the Company, and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2015 , the Company was in compliance with its debt limits.

Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program.

Subsidiary Project Credit Facilities

In connection with the construction of solar facilities by RE Tranquillity LLC, RE Roserock LLC, and RE Garland Holdings LLC, indirect subsidiaries of the Company, each subsidiary entered into separate credit agreements (Project Credit Facilities), which are non-recourse to the Company (other than the subsidiary party to the agreement). Each Project Credit Facility provides (a) a senior secured construction loan credit facility, (b) a senior secured bridge loan facility, and (c) a senior secured letter of credit facility and is secured by the membership interests of project companies. Proceeds from the Project Credit Facilities are being used to finance project costs related to the solar facility currently under construction. Each Project Credit Facility is secured by the assets of the applicable project subsidiary and membership interests of the applicable project subsidiary. The table below summarizes each Project Credit Facility as of December 31, 2015 .

Project	Maturity Date	Construction Loan Facility	Bridge Loan Facility	Total	Total Undrawn	Letter of Credit Facility	Total Undrawn
					(in millions)		
Tranquillity	Earlier of COD or December 31, 2016	$ 86	$ 172	$ 258	$ 147	$ 77	$ 26
Roserock	Earlier of COD or November 30, 2016	63	180	243	243	23	23
Garland	Earlier of COD or November 30, 2016	86	308	394	368	49	32
Total		$ 235	$ 660	$ 895	$ 758	$ 149	$ 81

The total amount outstanding on the Project Credit Facilities as of December 31, 2015 was $137 million at a weighted average interest rate of 2.0% and is included in notes payable in the balance sheet.

The Company expects to repay these Project Credit Facilities from its traditional sources of capital upon their maturity.

Commercial Paper Program

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. Commercial paper is included in notes payable in the balance sheets as noted below:

	Commercial Paper at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2015	**$ —**	**N/A**
December 31, 2014	$ 195	0.4%

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

7. COMMITMENTS

Fuel Agreements

SCS, as agent for the Company and the traditional operating companies, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the operating facilities which are not recognized on the Company's balance sheets. In 2015 , 2014 , and 2013 , the Company incurred fuel expense of $441 million , $596 million , and $474 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.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and Southern Company's traditional operating companies. Under these agreements, each of the traditional operating companies and the Company may be jointly and severally liable. Southern Company has entered into keep-well agreements with each of the traditional operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of the Company as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $7 million , $4 million , and $2 million for 2015 , 2014 , and 2013 , respectively. These amounts include contingent rent expense related to a land lease based on escalation in the Consumer Price Index for All Urban Consumers. The Company includes step rents, escalations, lease concessions, and lease extensions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term. As of December 31, 2015 , estimated minimum lease payments under operating leases were $11 million in 2016 , $12 million in 2017 , $12 million in 2018 , $12 million in 2019 , $13 million in 2020 , and $595 million in 2021 and thereafter. The majority of the committed future expenditures are related to land leases for solar and wind facilities.

Redeemable Noncontrolling Interests

TRE can require the Company to purchase its redeemable noncontrolling interests in STR, which owns various solar facilities contracted under long-term PPAs, at fair market value pursuant to the partnership agreement. As of December 31, 2015 , the redeemable noncontrolling interests were $43 million .

See Note 10 for additional information.

8. FAIR VALUE MEASUREMENTS

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

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

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, 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:				
Energy-related derivatives	$ —	$ 4	$ —	$ 4
Interest rate derivatives	—	3	—	3
Cash equivalents	511	—	—	511
Total	$ 511	$ 7	$ —	$ 518
Liabilities:				
Energy-related derivatives	$ —	$ 3	$ —	$ 3

As of December 31, 2014 , 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, 2014:	**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	$ —	$ 5	$ —	$ 5
Cash equivalents	18	—	—	18
Total	$ 18	$ 5	$ —	$ 23
Liabilities:				
Energy-related derivatives	$ —	$ 4	$ —	$ 4

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflect the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 9 for additional information on how these derivatives are used.

As of December 31, 2015 and 2014 , 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, including securities due within one year:		
2015	**$ 3,122**	**$ 3,117**
2014	$ 1,610	$ 1,785

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 available to the Company.

9. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 8 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. The Company has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity.

Energy-related derivative contracts are accounted for under one of two methods:

- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2015 , the net volume of energy-related derivative contracts for natural gas positions totaled 10 million mmBtu, all of which expire by 2017 , which is the longest non-hedge date. At December 31, 2015 , the net volume of energy-related derivative contracts for power positions was immaterial.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 1 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2016 is immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives from time to time to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

At December 31, 2015 , 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, 2015
	(in millions)						*(in millions)*
Derivatives not Designated as Hedges							
	$ 65	(a,d)	3-month LIBOR	2.50%	October 2016	(e)	$ 1
	47	(b,d)	3-month LIBOR	2.21%	October 2016	(e)	1
	65	(c,d)	3-month LIBOR	2.21%	November 2016	(f)	1
Total	$ 177						$ 3

(a) Swaption at RE Tranquillity LLC. See Note 2 for additional information.
(b) Swaption at RE Roserock LLC. See Note 2 for additional information.
(c) Swaption at RE Garland Holdings LLC. See Note 2 for additional information.
(d) Amortizing notional amount.
(e) Represents the mandatory settlement date. Settlement amount will be based on a 15 -year amortizing swap.
(f) Represents the mandatory settlement date. Settlement amount will be based on a 12 -year amortizing swap.

The Company has deferred gains and losses in AOCI related to past cash flow hedges that are expected to be amortized into earnings through 2016. The estimated pre-tax loss that will be reclassified from AOCI to interest expense for the 12-month period ending December 31, 2016 is immaterial.

Derivative Financial Statement Presentation and Amounts

At December 31, 2015 and 2014 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Assets from risk management activities	**$ 3**	$ —	Other current liabilities	**$ 2**	$ —
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Assets from risk management activities	**$ 1**	$ 5	Other current liabilities	**$ 1**	$ 4
Interest rate derivatives:	Assets from risk management activities	**3**	—	Other current liabilities	**—**	—
Total derivatives not designated as hedging instruments		**$ 4**	$ 5		**$ 1**	$ 4
Total		**$ 7**	$ 5		**$ 3**	$ 4

NOTES (continued)
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The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2015 and 2014 are presented in the following tables. Interest rate derivatives presented in the tables above do not have amounts available for offset and are therefore excluded from the offsetting disclosure tables below.

Fair Value					
Assets	**2015**	2014	**Liabilities**	**2015**	2014
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 4**	$ 5	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 3**	$ 4
Gross amounts not offset in the Balance Sheet [(b)]	**(1)**	—	Gross amounts not offset in the Balance Sheet [(b)]	**(1)**	—
Net energy-related derivative assets	**$ 3**	$ 5	**Net energy-related derivative liabilities**	**$ 2**	$ 4

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

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

	Gain (Loss) Reclassified from AOCI into Income (Effective Portion)			
Derivatives in Cash Flow Hedging Relationships		**Amount**		
Derivative Category	**Statements of Income Location**	**2015**	2014	2013
			(in millions)	
Interest rate derivatives	Interest expense, net of amounts capitalized	**$ (1)**	$ (1)	$ (6)

For the years ended December 31, 2015 , 2014 , and 2013 , the pre-tax effects of energy-related derivatives designated as cash flow hedging instruments recognized in OCI and reclassified from AOCI into earnings were immaterial.

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

The pre-tax effects of energy-related derivatives and interest rate derivatives not designated as hedging instruments on the Company's statements of income were not material for any year 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, 2015 , the amount of collateral posted with its derivative counterparties was immaterial.

At December 31, 2015 , the fair value of derivative liabilities with contingent features was immaterial. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $52 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

10. NONCONTROLLING INTERESTS

The following table details the components of redeemable noncontrolling interests for the years ended December 31:

	2015	2014	2013
		(in millions)	
Beginning balance	**$ 39**	$ 29	$ 8
Net income attributable to redeemable noncontrolling interests	**2**	4	4
Distributions to redeemable noncontrolling interests	**—**	(1)	—
Capital contributions from redeemable noncontrolling interests	**2**	7	17
Ending balance	**$ 43**	$ 39	$ 29

For the years ended December 31, 2015 and 2014, net income included in the consolidated statements of changes in stockholders' equity is reconciled to net income presented in the consolidated statements of income as follows:

	2015	2014
	(in millions)	
Net income attributable to the Company	**$ 215**	$ 172
Net income (loss) attributable to noncontrolling interests	**12**	(1)
Net income attributable to redeemable noncontrolling interests	**2**	4
Net income	**$ 229**	$ 175

For the year ended December 31, 2013 , net income attributable to redeemable noncontrolling interests was $4 million and was included in "Other income (expense), net" in the consolidated statements of income.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2015 and 2014 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income Attributable to the Company
		(in millions)	
March 2015	**$ 348**	**$ 67**	**$ 33**
June 2015	**337**	**75**	**46**
September 2015	**401**	**129**	**102**
December 2015	**304**	**55**	**34**
March 2014	$ 351	$ 59	$ 33
June 2014	329	51	31
September 2014	435	105	64
December 2014	386	40	44

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

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2011 - 2015
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	2015	2014	2013	2012	2011
Operating Revenues (in millions):					
Wholesale — non-affiliates	**$ 964**	$ 1,116	$ 923	$ 754	$ 871
Wholesale — affiliates	**417**	383	346	425	359
Total revenues from sales of electricity	**1,381**	1,499	1,269	1,179	1,230
Other revenues	**9**	2	6	7	6
Total	**$ 1,390**	$ 1,501	$ 1,275	$ 1,186	$ 1,236
Net Income Attributable to the Company (in millions)	**$ 215**	$ 172	$ 166	$ 175	$ 162
Cash Dividends on Common Stock (in millions)	**$ 131**	$ 131	$ 129	$ 127	$ 91
Return on Average Common Equity (percent)	**10.16**	10.39	10.73	11.72	11.88
Total Assets (in millions) (a)(b)	**$ 8,905**	$ 5,233	$ 4,417	$ 3,771	$ 3,569
Gross Property Additions and Acquisitions (in millions)	**$ 1,005**	$ 942	$ 633	$ 241	$ 255
Capitalization (in millions):					
Common stock equity	**$ 2,483**	$ 1,752	$ 1,564	$ 1,522	$ 1,469
Redeemable noncontrolling interests	**43**	39	29	8	4
Noncontrolling interests	**781**	219	—	—	—
Long-term debt (a)	**2,719**	1,085	1,607	1,297	1,293
Total (excluding amounts due within one year)	**$ 6,026**	$ 3,095	$ 3,200	$ 2,827	$ 2,766
Capitalization Ratios (percent):					
Common stock equity	**41.2**	56.6	48.9	53.8	53.1
Redeemable noncontrolling interests	**0.7**	1.3	0.9	0.3	0.1
Noncontrolling interests	**13.0**	7.1	—	—	—
Long-term debt (a)	**45.1**	35.0	50.2	45.9	46.8
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Kilowatt-Hour Sales (in millions):					
Wholesale — non-affiliates	**18,544**	19,014	15,111	15,637	16,090
Wholesale — affiliates	**16,567**	11,194	9,359	16,373	11,774
Total	**35,111**	30,208	24,470	32,010	27,864
Plant Nameplate Capacity Ratings (year-end) (megawatts) (c)	**9,808**	9,185	8,924	8,764	7,908
Maximum Peak-Hour Demand (megawatts):					
Winter	**3,923**	3,999	2,685	3,018	3,255
Summer	**4,249**	3,998	3,271	3,641	3,589
Annual Load Factor (percent)	**49.0**	51.8	54.2	48.6	51.0
Plant Availability (percent) (d)	**93.1**	91.8	91.8	92.9	93.9
Source of Energy Supply (percent):					
Natural gas	**89.5**	86.0	88.5	91.0	89.2
Alternative (Solar, Wind, and Biomass)	**4.3**	2.9	1.1	0.5	0.2
Purchased power —					
From non-affiliates	**4.7**	6.4	6.4	7.2	6.7
From affiliates	**1.5**	4.7	4.0	1.3	3.9
Total	**100.0**	100.0	100.0	100.0	100.0

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $11 million, $12 million, $9 million, and $10 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-03. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(b) A reclassification of deferred tax assets from Total Assets of $306 million, $- million, $- million, and $2 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-17. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(c) Plant nameplate capacity ratings include 100% of all solar facilities. When taking into consideration the Company's 90% equity interest in STR and 51% equity interest in SRP, the Company's equity portion of total nameplate capacity for 2015 is 9,595 MW.

(d) Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

PART III

Items 10, 11, 12 (other than the information under "Code of Ethics" below in Item 10), 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2016 Annual Meeting of Stockholders. Specifically, reference is made to "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Director Compensation," "Director Deferred Compensation Plan," and "Director Compensation Table" for Item 11, "Stock Ownership Table" and "Executive Compensation" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Independent Registered Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12 (other than the information under "Code of Ethics" below in Item 10), 13, and 14 for Alabama Power, Georgia Power, and Mississippi Power are incorporated by reference to the Definitive Information Statements of Alabama Power, Georgia Power, and Mississippi Power relating to each of their respective 2016 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Committee Interlocks and Insider Participation," "Director Compensation," "Director Deferred Compensation Plan," and "Director Compensation Table" for Item 11, "Stock Ownership Table" and "Executive Compensation" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Independent Registered Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13, and 14 for Gulf Power are contained herein.

Items 10, 11, 12, and 13 for Southern Power are omitted pursuant to General Instruction I(2)(c) of Form 10-K. Item 14 for Southern Power is contained herein.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of directors of Gulf Power **(1)**

S. W. Connally, Jr. Chairman, President, and Chief Executive Officer Age 46 Served as Director since 2012	**Julian B. MacQueen (2)** Age 65 Served as Director since 2013
Allan G. Bense (2) Age 64 Served as Director since 2010	**J. Mort O'Sullivan, III (2)** Age 64 Served as Director since 2010
Deborah H. Calder (2) Age 55 Served as Director since 2010	**Michael T. Rehwinkel (2)** Age 59 Served as Director since 2013
William C. Cramer, Jr. (2) Age 63 Served as Director since 2002	**Winston E. Scott (2)** Age 65 Served as Director since 2003

(1) *Ages listed are as of December 31, 2015.*
(2) *No position other than director.*

Each of the above is currently a director of Gulf Power, serving a term running from the last annual meeting of Gulf Power's shareholders (June 30, 2015) for one year until the next annual meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as a director, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of executive officers of Gulf Power **(1)**

S. W. Connally, Jr. Chairman, President, and Chief Executive Officer Age 46 Served as Executive Officer since 2012	**Michael L. Burroughs** Vice President — Senior Production Officer Age 55 Served as Executive Officer since 2010
Jim R. Fletcher Vice President — External Affairs and Corporate Services Age 49 Served as Executive Officer since 2014	**Wendell E. Smith** Vice President — Power Delivery Age 50 Served as Executive Officer since 2014
Xia Liu Vice President and Chief Financial Officer Age 45 Served as Executive Officer since 2015	**Bentina C. Terry** Vice President — Customer Service and Sales Age 45 Served as Executive Officer since 2007

(1) *Ages listed are as of December 31, 2015.*

Each of the above is currently an executive officer of Gulf Power, serving a term until the next annual organizational meeting of the Board of Directors or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as an officer, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of certain significant employees. *None.*

Family relationships. *None.*

Business experience. *Unless noted otherwise, each director has served in his or her present position for at least the past five years.*

<u>*DIRECTORS*</u>

Gulf Power's Board of Directors possesses collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and Gulf Power's industry.

S. W. Connally, Jr. - Mr. Connally was elected Chairman in July 2015 and has served as President, Chief Executive Officer, and Director since July 2012. Mr. Connally has also served as Chairman of Gulf Power's Board of Directors since July 2012. Mr. Connally previously served as Senior Vice President and Chief Production Officer of Georgia Power from August 2010 through June 2012.

Allan G. Bense - Panama City businessman and former Speaker of the Florida House of Representatives. Mr. Bense is a partner in several companies involved in road building, mechanical contracting, insurance, general contracting, golf courses, and farming. Mr. Bense served as Vice Chair of Enterprise Florida, the economic development agency for the state, from January 2009 to January 2011. Mr. Bense also has been a member of the board of directors of Capital City Bank Group, Inc. since 2013.

Deborah H. Calder - Executive Vice President for Navy Federal Credit Union since 2014. From 2008 to 2014, she served as Senior Vice President. Ms. Calder directs the day-to-day operations of more than 4,500 employees and the ongoing construction of Navy Federal Credit Union's campus in the Pensacola area. Ms. Calder has been with Navy Federal Credit Union for over 24 years, serving in previous positions as Vice President of Consumer and Credit Card Lending, Vice President of Collections, Vice President of Call Center Operations, and Assistant Vice President of Credit Cards.

William C. Cramer, Jr. - President and Owner of automobile dealerships in Florida and Alabama. Mr. Cramer has been an authorized Chevrolet dealer for over 26 years. In 2009, Mr. Cramer became an authorized dealer of Cadillac, Buick, and GMC vehicles.

Julian B. MacQueen - Founder and Chief Executive Officer of Innisfree Hotels, Inc. He is currently a member of the American Hotel & Lodging Association and a director of the Beach Community Bank.

J. Mort O'Sullivan, III - Managing Member of the Gulf Coast division of Warren Averett, LLC, a CPA and Advisory firm. Mr. O'Sullivan currently focuses on consulting and management advisory services to clients, while continuing to offer his expertise in litigation support, business valuations, wealth management, and mergers and acquisitions. He is a registered investment advisor.

Michael T. Rehwinkel - Mr. Rehwinkel previously served as Executive Chairman of EVRAZ North America, a steel manufacturer, from July 2013 to December 2015 and as Chief Executive Officer and President from February 2010 to July

2013. Mr. Rehwinkel also served as Chairman of the American Iron and Steel Institute in 2012 and 2013. Mr. Rehwinkel has more than 30 years of industrial business and leadership experience.

Winston E. Scott - Senior Vice President for External Relations and Economic Development, Florida Institute of Technology since March 2012. He previously served as Dean, College of Aeronautics, Florida Institute of Technology, Melbourne, Florida from August 2008 through March 2012. Mr. Scott is also a member of the board of directors of Environmental Tectonics Corporation.

EXECUTIVE OFFICERS

Michael L. Burroughs - Vice President and Senior Production Officer since August 2010. He previously served as Manager of Georgia Power's Plant Yates from September 2007 to July 2010.

Jim R. Fletcher - Vice President of External Affairs and Corporate Services since March 2014. He previously served as Vice President of Governmental and Regulatory Affairs for Georgia Power from January 2011 to February 2014 and Regulatory Affairs Manager for Georgia Power from March 2006 to January 2011.

Xia Liu - Vice President and Chief Financial Officer since June 2015. She previously served as Treasurer of Southern Company and Senior Vice President of Finance and Treasurer of SCS from March 2014 to June 2015 and Assistant Treasurer of Southern Company and Vice President of Finance and Assistant Treasurer of SCS from July 2010 to March 2014.

Wendell E. Smith - Vice President of Power Delivery since March 2014. He previously served as the General Manager of Distribution Engineering, Construction and Maintenance and Distribution Operations Systems for Georgia Power from January 2012 to February 2014, Transmission Construction Manager for Georgia Power from February 2011 to December 2011, and Distribution Manager for Georgia Power from March 2005 to February 2011.

Bentina C. Terry - Vice President of Customer Service and Sales since March 2014. She previously served as Vice President of External Affairs and Corporate Services from March 2007 to March 2014.

Involvement in certain legal proceedings. None.

Promoters and Control Persons. None.

Section 16(a) Beneficial Ownership Reporting Compliance. No late filings to report.

Code of Ethics

The registrants collectively have adopted a code of business conduct and ethics (Code of Ethics) that applies to each director, officer, and employee of the registrants and their subsidiaries. The Code of Ethics can be found on Southern Company's website located at www.southerncompany.com . The Code of Ethics is also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Any amendment to or waiver from the Code of Ethics that applies to executive officers and directors will be posted on the website.

Corporate Governance

Southern Company has adopted corporate governance guidelines and committee charters. The corporate governance guidelines and the charters of Southern Company's Audit Committee, Compensation and Management Succession Committee, Finance Committee, Governance Committee, and Nuclear/Operations Committee can be found on Southern Company's website located at www.southerncompany.com . The corporate governance guidelines and charters are also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

Southern Company owns all of Gulf Power's outstanding common stock and Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance. In addition, under the rules of the SEC, Gulf Power is exempt from the audit committee requirements of Section 301 of the Sarbanes-Oxley Act of 2002 and, therefore, is not required to have an audit committee or an audit committee report on whether it has an audit committee financial expert.

Item 11. EXECUTIVE COMPENSATION

GULF POWER

COMPENSATION DISCUSSION AND ANALYSIS (CD&A)

In this CD&A and this Form 10-K, references to the "Compensation Committee" are to the Compensation and Management Succession Committee of the Board of Directors of Southern Company.

This section describes the compensation program for Gulf Power's Chief Executive Officer and Chief Financial Officer in 2015, as well as each of its other three most highly compensated executive officers serving at the end of the year.

S. W. Connally, Jr.	Chairman, President, and Chief Executive Officer
Xia Liu	Vice President and Chief Financial Officer
Jim R. Fletcher	Vice President
Wendell E. Smith	Vice President
Bentina C. Terry	Vice President

Also described is the compensation of Gulf Power's former Vice President and Chief Financial Officer, Richard S. Teel, who became Vice President of Fuel Services for SCS on June 1, 2015. Prior to becoming Vice President and Chief Financial Officer of Gulf Power, Ms. Liu served as Senior Vice President of Finance and Treasurer of SCS and Treasurer of Southern Company. Collectively, these officers are referred to as the named executive officers.

EXECUTIVE SUMMARY

Pay for Performance

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2015.

	Salary ($) (1)	% of Total	Annual Cash Incentive Award ($) (2)	% of Total	Long-term Equity Incentive Award ($) (3)	% of Total
S. W. Connally, Jr.	420,758	31%	391,000	29%	553,946	41%
X. Liu	265,380	44%	188,996	31%	154,865	25%
R. S. Teel	266,977	44%	184,693	30%	156,703	26%
J. R. Fletcher	238,711	43%	169,891	31%	144,315	26%
W. E. Smith	203,401	49%	128,461	31%	81,813	20%
B. C. Terry	278,682	43%	198,007	31%	168,195	26%

(1) Salary is the actual amount paid in 2015.
(2) Annual Cash Incentive Award is the actual amount earned in 2015 under the Performance Pay Program based on achievement of performance goals.
(3) Long-Term Equity Incentive Award reflects the target value of the performance shares granted in 2015 under the Performance Share Program.

The executive compensation program places significant focus on rewarding performance. The program is performance-based in several respects:

- Business unit financial and operational performance and Southern Company earnings per share (EPS), based on actual results as adjusted by the Compensation Committee, compared to target performance levels established early in the year, determine the actual payouts under the annual cash incentive award program (Performance Pay Program).

- Southern Company's total shareholder return (TSR) compared to those of industry peers, cumulative EPS, and equity-weighted return on equity (ROE) over a three-year period lead to higher or lower payouts under the long-term equity incentive award program (Performance Share Program).

In support of this performance-based pay philosophy, Gulf Power has no general employment contracts with the named executive officers.

The pay-for-performance principles apply not only to the named executive officers but to hundreds of Gulf Power's employees. The Performance Pay Program covers almost all of the approximately 1,400 employees of Gulf Power. Performance shares were granted to 142 employees of Gulf Power. These programs engage employees and encourage alignment of their interests with Gulf Power’s customers and Southern Company’s stockholders.

Gulf Power's financial and operational goal results and Southern Company's EPS goal results for 2015, as adjusted and further described in this CD&A, are shown below:

Financial: 125% of Target	Operational: 196% of Target	EPS: 151% of Target

Southern Company’s annualized TSR has been:

1-Year: -0.1%	3-Year: 7.9%	5-year: 9.0%

These levels of achievement, as adjusted, resulted in payouts that were aligned with Gulf Power's and Southern Company's performance**.**

Compensation Philosophy

Gulf Power's compensation program is based on the following beliefs:

- Employees’ commitment and performance have a significant impact on achieving business results;
- Compensation and benefits offered must attract, retain, and engage employees and must be financially sustainable;
- Compensation should be consistent with performance: higher pay for higher performance and lower pay for lower performance; and
- Both business drivers and culture should influence the compensation and benefit program.

Based on these beliefs, the Compensation Committee believes that Gulf Power’s executive compensation program should:

- Be competitive with Gulf Power’s industry peers;
- Motivate and reward achievement of Gulf Power’s goals;
- Be aligned with the interests of Southern Company’s stockholders and Gulf Power’s customers; and
- Not encourage excessive risk-taking.

Executive compensation is targeted at the market median of industry peers, but actual compensation is primarily determined by achievement of Gulf Power’s and Southern Company's business goals. Gulf Power believes that focusing on the customer drives achievement of financial objectives and delivery of a premium, risk-adjusted total shareholder return for Southern Company’s stockholders. Therefore, short-term performance pay is based on achievement of Gulf Power’s operational and financial performance goals and Southern Company's EPS. Long-term performance pay is tied to Southern Company's TSR performance, cumulative EPS, and equity-weighted ROE .

Key Compensation Practices

- Annual pay risk assessment required by the Compensation Committee charter.
- Retention by the Compensation Committee of an independent compensation consultant, Pay Governance, that provides no other services to Gulf Power or Southern Company.
- Inclusion of a claw-back provision that permits the Compensation Committee to recoup performance pay from any employee if determined to have been based on erroneous results, and requires recoupment from an executive officer in the event of a material financial restatement due to fraud or misconduct of the executive officer.
- No excise tax gross-up on change-in-control severance arrangements.
- Provision of limited ongoing perquisites with no income tax gross-ups for the Chairman, President, and Chief Executive Officer, except on certain relocation-related benefits.

- "No-hedging" provision in Gulf Power's insider trading policy that is applicable to all employees.
- Policy against pledging of Southern Company stock applicable to all executive officers and directors of Southern Company, including the Gulf Power Chief Executive Officer.
- Strong stock ownership requirements that are being met by all named executive officers.

Establishing Executive Compensation

The Compensation Committee establishes the Southern Company system executive compensation program. In doing so, the Compensation Committee relies on input from its independent compensation consultant, Pay Governance. The Compensation Committee also relies on input from Southern Company's Human Resources staff and, for individual executive officer performance, from Southern Company's and Gulf Power's respective Chief Executive Officers. The role and information provided by each of these sources is described throughout this CD&A.

Consideration of Southern Company Stockholder Advisory Vote on Executive Compensation

The Compensation Committee considered the stockholder vote on Southern Company's executive compensation at the Southern Company 2015 annual meeting of stockholders. In light of the significant support of Southern Company's stockholders (94% of votes cast voting in favor of the proposal) and the actual payout levels of the performance-based compensation program, the Compensation Committee continues to believe that the executive compensation program is competitive, aligned with Gulf Power's and Southern Company's financial and operational performance, and in the best interests of Gulf Power's customers and Southern Company's stockholders.

ESTABLISHING MARKET-BASED COMPENSATION LEVELS

Pay Governance develops and presents to the Compensation Committee a competitive market-based compensation level for Gulf Power's Chief Executive Officer. Southern Company's Human Resources staff develops competitive market-based compensation levels for the other Gulf Power named executive officers. The market-based compensation levels for both are developed from a size-appropriate energy services executive compensation survey database. The survey participants, listed below, are utilities with revenues of $1 billion or more.

Market data for the Chief Executive Officer position and other positions in terms of scope of responsibilities that most closely resemble the positions held by the named executive officers is reviewed. When appropriate, the market data is size-adjusted, up or down, to accurately reflect comparable scopes of responsibilities. Based on that data, a total target compensation opportunity is established for each named executive officer. Total target compensation opportunity is the sum of base salary, the annual cash incentive award at target performance level, and the long-term equity incentive award at target performance level. Actual compensation paid may be more or less than the total target compensation opportunity based on actual performance above or below target performance levels. As a result, the compensation program is designed to result in payouts that are market-appropriate given Gulf Power's and Southern Company's performance for the year or period.

A specified weight was not targeted for base salary, the annual cash incentive award, or the long-term equity incentive award as a percentage of total target compensation opportunities, nor did amounts realized or realizable from prior compensation serve to increase or decrease 2015 compensation amounts.

Total target compensation opportunities for senior management as a group, including the named executive officers, are managed to be at the median of the market for companies of similar size in the electric utility industry. Therefore, some executives may be paid above and others below market. This practice allows for differentiation based on time in the position, scope of responsibilities, and individual performance. The differences in the total pay opportunities for each named executive officer are based almost exclusively on the differences indicated by the market data for persons holding similar positions. Because of the use of market data from a large number of industry peer companies for positions that are not identical in terms of scope of responsibility from company to company, differences are not considered to be material and the compensation program is believed to be market-appropriate, as long as senior management as a group is within an appropriate range. Generally, compensation is considered to be within an appropriate range if it is not more or less than 15% of the applicable market data.

AGL Resources Inc.	EP Energy Corporation	Pacific Gas & Electric Company
Allete, Inc.	EQT Corporation	Pepco Holdings, Inc.
Alliant Energy Corporation	Eversource International	Pinnacle West Capital Corporation
Ameren Corporation	Exelon Corporation	PNM Resources Inc.
American Electric Power Company, Inc.	FirstEnergy Corp.	Portland General Electric Company
American Water Works Company, Inc.	First Solar Inc.	PPL Corporation
Areva Inc.	GE Energy	Public Service Enterprise Group Inc.
Atmos Energy Corporation	Iberdrola USA, Inc.	Puget Sound Energy, Inc.
Austin Energy	Idaho Power Company	Questar Corporation
Avista Corporation	Integrys Energy Group, Inc.	Salt River Project
Bg US Services, Inc.	Invenergy LLC	Santee Cooper
Black Hills Corporation	JEA	SCANA Corporation
Boardwalk Pipeline Partners, L.P.	Kinder Morgan Energy Partners, L.P.	Sempra Energy
Calpine Corporation	Laclede Group, Inc.	Southwest Gas Corporation
CenterPoint Energy, Inc.	LG&E and KU Energy LLC	Spectra Energy Corp.
Cleco Corporation	Lower Colorado River Authority	TECO Energy, Inc.
CMS Energy Corporation	MDU Resources Group, Inc.	Tennessee Valley Authority
Consolidated Edison, Inc.	Monroe Energy	Tervita Corporation
Dominion Resources, Inc.	National Grid USA	The AES Corporation
DTE Energy Company	Nebraska Public Power District	The Babcock & Wilcox Company
Duke Energy Corporation	New Jersey Resources Corporation	The Williams Companies, Inc.
Dynegy Inc.	New York Power Authority	TransCanada Corporation
Edison International	NextEra Energy, Inc.	Tri-State Generation & Transmission Association, Inc.
ElectriCities of North Carolina	NiSource Inc.	
Energen Corporation	NorthWestern Corporation	UGI Corporation
Energy Future Holdings Corp.	NOVA Chemicals Corporation	UIL Holdings
Energy Solutions, Inc.	NRG Energy, Inc.	UNS Energy Corporation
Energy Transfer Partners, L.P.	OGE Energy Corp.	Vectren Corporation
ENGIE Energy North America	Omaha Public Power District	Westar Energy, Inc.
EnLink Midstream	Oncor Electric Delivery Company LLC	Wisconsin Energy Corporation
Entergy Corporation	ONE Gas, Inc.	Xcel Energy Inc.

Executive Compensation Program

The primary components of the 2015 executive compensation program include:

- Short-term compensation
    - Base salary
    - Performance Pay Program
- Long-term compensation
    - Performance Share Program
- Benefits

The performance-based compensation components are linked to Gulf Power's financial and operational performance as well as Southern Company's financial and stock price performance, including TSR, EPS, and ROE. The executive compensation program is approved by the Compensation Committee, which consists entirely of independent directors of Southern Company. The Compensation Committee believes that the executive compensation program is a balanced program that provides market-based compensation and motivates and rewards performance.

2015 Base Salary

Most employees, including all of the named executive officers, received base salary increases in 2015.

With the exception of Southern Company executive officers, including Mr. Connally, base salaries for all Southern Company system officers are within a position level with a base salary range that is established by Southern Company Human Resources staff using the market data described above. Each officer is within one of these established position levels based on the scope of responsibilities that most closely resemble the positions included in the market data described above. The base salary level for individual officers is set within the applicable pre-established range. Factors that influence the specific base salary level within the range include the need to retain an experienced team, internal equity, time in position, and individual performance. Individual performance includes the degree of competence and initiative exhibited and the individual's relative contribution to the achievement of financial and operational goals in prior years.

Base salaries are reviewed annually in February and changes are made effective March 1. The base salary levels established early in the year for the named executive officers were set within the applicable position level salary range and were recommended by the individual named executive officer's supervisor and approved by Southern Company's Chief Executive Officer. Mr. Connally's base salary was approved by the Compensation Committee.

	March 1, 2014 Base Salary ($)	March 1, 2015 Base Salary ($)
S. W. Connally, Jr.	398,242	426,119
X. Liu	241,942	258,124
R. S. Teel	253,540	261,168
J. R. Fletcher	211,255	240,470
W. E. Smith	187,314	204,555
B. C. Terry	272,039	280,264

Ms. Liu was Senior Vice President of Finance and Treasurer of SCS and Treasurer of Southern Company prior to her promotion to Vice President and Chief Financial Officer at Gulf Power on June 1, 2015. At that time, her base salary was increased to $273,611.

When Mr. Teel was promoted from Vice President and Chief Financial Officer of Gulf Power to Vice President of Fuel Services at SCS on June 1, 2015, his base salary was increased to $274,227.

2015 Performance-Based Compensation

This section describes short-term and long-term performance-based compensation for 2015.

Achieving Operational and Financial Performance Goals - The Guiding Principle for Performance-Based Compensation

The Southern Company system's number one priority is to continue to provide customers outstanding reliability and superior service at reasonable prices while achieving a level of financial performance that benefits Southern Company's stockholders in the short and long term. Operational excellence and business unit and Southern Company financial performance are integral to the achievement of business results that benefit customers and stockholders.

Therefore, in 2015, Gulf Power strove for and rewarded:

- Continuing industry-leading reliability and customer satisfaction, while maintaining reasonable retail prices;
- Meeting energy demand with the best economic and environmental choices;
- Long-term, risk-adjusted Southern Company TSR;
- Achieving net income goals to support the Southern Company financial plan and dividend growth; and
- Financial integrity - an attractive risk-adjusted return and sound financial policy.

The performance-based compensation program is designed to encourage achievement of these goals.

The Southern Company Chief Executive Officer, with the assistance of Southern Company’s Human Resources staff, recommended to the Compensation Committee the program design and award amounts for senior management, including the named executive officers.

2015 Annual Performance-Based Pay Program

Annual Performance Pay Program Highlights

- Changes in 2015
  - Added individual performance goals for the Chief Executive Officer
- Rewards achievement of annual performance goals; performance results can range from 0% to 200% of target, based on actual level of goal achievement
  - EPS: earned at 151% of target
  - Net Income: earned at 125% of target
  - Operations: earned at 196% of target
- 2015 Payout: Exceeded target performance
  - Chief Executive Officer payout at 153% of target
  - Average of the other named executive officers' payout at 155% of target

Overview of Program Design

Almost all employees of Gulf Power, including the named executive officers, are participants.

The performance goals are set at the beginning of each year by the Compensation Committee and include financial and operational goals for all employees. In setting goals, the Compensation Committee relies on information on financial and operational goals from the Finance Committee and the Nuclear/Operations Committee of the Southern Company Board of Directors, respectively.

- **Business Unit Financial Goal: Net Income**
  For Southern Company’s traditional operating companies, including Gulf Power, and Southern Power, the business unit financial performance goal is net income. There is no separate net income goal for Southern Company as a whole. Overall Southern Company performance is determined by the equity-weighted average of the business unit net income goal payouts.

- **Business Unit Operational Goals: Varies by business unit**
  For Southern Company’s traditional operating companies, including Gulf Power, operational goals are customer satisfaction, safety, major projects (Georgia Power and Mississippi Power), culture, transmission and distribution system reliability, and plant availability. Each of these operational goals is explained in more detail under Goal Details below. The level of achievement for each operational goal is determined according to the respective performance schedule, and the total operational goal performance is determined by the weighted average result. Each business unit has its own operational goals.

- **Southern Company Financial Goal: EPS**
  EPS is defined as Southern Company’s net income from ongoing business activities divided by average shares outstanding during the year, as adjusted and approved by the Compensation Committee. The EPS performance measure is applicable to all participants in the Performance Pay Program.

- **Individual Performance Goals for the Chief Executive Officer**
  Beginning in 2015, the Performance Pay Program incorporates individual goals for all executive officers of Southern Company, including Mr. Connally. The Compensation Committee sets the individual goals for Mr. Connally and evaluates his performance at the end of the year. The individual goals account for 10% of Mr. Connally's Performance Pay Program goals.

Under the terms of the program, no payout can be made if events occur that impact Southern Company's financial ability to fund the Southern Company common stock (Common Stock) dividend.

Goal Details

Operational Goals	Description	Why It Is Important
Customer Satisfaction	Customer satisfaction surveys evaluate performance. The survey results provide an overall ranking for each traditional operating company, including Gulf Power, as well as a ranking for each customer segment: residential, commercial, and industrial.	Customer satisfaction is key to operations. Performance of all operational goals affects customer satisfaction.
Safety	Southern Company's Target Zero program is focused on continuous improvement in striving for a safe work environment. The performance is measured by the applicable company's ranking, as compared to peer utilities in the Southeastern Electric Exchange.	Essential for the protection of employees, customers, and communities.
Major Projects - Plant Vogtle Units 3 and 4 and Kemper IGCC	The Southern Company system is committed to the safe, compliant, and high-quality construction and licensing of two new nuclear generating units under construction at Plant Vogtle Units 3 and 4 and the Kemper IGCC, as well as excellence in transition to operations and prudent decision-making related to these two major projects. A combination of subjective and objective measures is considered in assessing the degree of achievement. Annual goals are established that are designed to achieve long-term project completion with a focus on validating technology and providing clean, reliable operation. An executive review committee is in place for each project to assess progress. Final assessments for each project are approved by either Southern Company’s Chief Executive Officer or Southern Company’s Chief Operating Officer and confirmed by the Nuclear/Operations Committee of Southern Company.	Strategic projects enable the Southern Company system to expand capacity to provide clean, safe, reliable, and affordable energy to customers across the region. Long-term projects are accomplished through achievement of annual goals over the life cycle of the project.
Culture	The culture goal seeks to improve Gulf Power's inclusive workplace. This goal includes measures for work environment (employee satisfaction survey), representation of minorities and females in leadership roles (subjectively assessed), and supplier diversity.	Supports workforce development efforts and helps to assure diversity of suppliers.
Reliability	Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on recent historical performance.	Reliably delivering power to customers is essential to Gulf Power's operations.
Availability	Peak season equivalent forced outage rate is an indicator of availability and efficient generation fleet operations during the months when generation needs are greatest. Availability is measured as a percentage of the hours of forced outages out of the total generation hours.	Availability of sufficient power during peak season fulfills the obligation to serve and provide customers with the least cost generating resources.
Nuclear Plant Operations	Nuclear plant performance is evaluated by measuring nuclear safety as rated by independent industry evaluators, as well as by a quantitative score comprised of various plant performance indicators. Plant reliability and operational availability are measured as a percentage of time the nuclear plant is operating. The reliability and availability metrics take generation reductions associated with planned outages into consideration.	Safe and efficient operation of the nuclear fleet is important for delivering clean energy at a reasonable price.

Financial Performance Goals	Description	Why It Is Important
EPS	Southern Company's net income from ongoing business activities divided by average shares outstanding during the year.	Supports commitment to provide Southern Company's stockholders solid, risk-adjusted returns and to support and grow the dividend.
Net Income	For the traditional operating companies, including Gulf Power, and Southern Power, the business unit financial performance goal is net income after dividends on preferred and preference stock. Overall corporate performance is determined by the equity-weighted average of the business unit net income goal payouts.	Supports delivery of Southern Company stockholder value and contributes to Gulf Power's and Southern Company's sound financial policies and stable credit ratings.

Individual Performance Goals (Mr. Connally only)	Description	Why It Is Important
Individual Factors	Focus on overall business performance as well as factors including leadership development, succession planning and fostering the culture and diversity of the organization.	Individual goals provide the Compensation Committee the ability to balance quantitative results with qualitative inputs by focusing on both business performance and behavioral aspects of leadership that lead to sustainable long-term growth.

The range of business unit and Southern Power net income goals and Southern Company EPS goals for 2015 is shown below.

Level of Performance	Alabama Power Net Income ($, in millions)	Georgia Power Net Income ($, in millions)	Gulf Power Net Income ($, in millions)	Mississippi Power Net Income ($, in millions)	Southern Power Net Income ($, in millions)	Southern Company EPS ($)
Maximum	821.0	1,312.0	158.0	212.2	225.0	2.96
Target	763.0	1,208.0	144.6	190.0	165.0	2.82
Threshold	704.0	1,103.0	131.3	167.8	105.0	2.68

The Compensation Committee approves threshold, target, and maximum performance levels for each of the operational goals. If goal achievement is below threshold, there is no payout associated with the applicable goal.

Calculating Payouts

All of the named executive officers are paid based on Southern Company EPS performance. With the exception of Ms. Liu and Mr. Teel, all of the named executive officers are paid based on Gulf Power net income and operational performance. Ms. Liu's payout is prorated based on the time she was employed at SCS and at Gulf Power. Mr. Teel's payout is prorated based on the amount of time he was employed at Gulf Power and SCS.

Actual 2015 goal achievement is shown in the following tables.

Operational Goal Results
Gulf Power (Mses. Liu and Terry and Messrs. Connally, Teel, Smith, and Fletcher)

Goal	Achievement
Customer Satisfaction	Maximum
Safety	Near maximum
Culture	Significantly above target
Reliability	Maximum
Availability	Maximum
Total Gulf Power Operational Goal Performance Factor	196%

Southern Company Corporate & Services (Ms. Liu and Mr. Teel)

Goal	Achievement
Customer Satisfaction	Maximum
Safety	Slightly below target
Major Projects - Plant Vogtle Units 3 and 4 annual objectives	Above target
Major Projects - Kemper IGCC annual objectives	At target
Culture	Above target
Reliability	Below target
Availability	Maximum
Total Southern Company Corporate & Services Operational Goal Performance Factor	147%

Financial Performance Goal Results

Goal	Result	Achievement Percentage (%)
Gulf Power Net Income	$148.0	125
Southern Power Net Income	$210.0	184
Corporate Net Income Result	Equity-Weighted Average	145
EPS (from ongoing business activities) as adjusted by the Compensation Committee	$2.86*	151

*The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. Southern Company's reported 2015 adjusted EPS result was $2.89. The reported adjusted EPS result excludes the impact of charges related to the Kemper IGCC, acquisition costs related to the Merger, and the settlement costs related to MC Asset Recovery, LLC. In addition to the these three items, the Compensation Committee approved a further adjustment for the earnings impact related to the termination of an asset purchase agreement for a portion of the Kemper IGCC. This additional adjustment reduced the Southern Company EPS result for Performance Pay Program compensation purposes from $2.89 to $2.86.

A total performance factor is determined by adding the applicable business unit financial and operational goal performance and the EPS results and dividing by three, except for Mr. Connally. For Mr. Connally, the business unit financial and operational goal performance and EPS results are worth 30% each of the total performance factor, while his individual performance goal result is worth the remaining 10%. The total performance factor is multiplied by the target Performance Pay Program opportunity to determine the payout for each named executive officer.

	Southern Company EPS Result (%)	Business Unit Financial Goal Result (%)	Business Unit Operational Goal Result (%)	Individual Goal Result (%)	Total Performance Factor (%)
S. W. Connally, Jr.	151	125	196	112	153
X. Liu (1)	151	145/125	147/196	N/A	148/157
R. S. Teel (2)	151	125/145	196/147	N/A	157/148
J. R. Fletcher	151	125	196	N/A	157
W. E. Smith	151	125	196	N/A	157
B. C. Terry	151	125	196	N/A	157

(1) Ms. Liu was Senior Vice President of Finance and Treasurer of SCS and Treasurer of Southern Company until her promotion to Vice President and Chief Financial Officer of Gulf Power on June 1, 2015. Under the terms of the program, Ms. Liu's Performance Pay Program results were prorated based on the time she served at each company.

(2) Mr. Teel was Gulf Power's Vice President and Chief Financial Officer until his promotion to Vice President of Fuel Services for SCS on June 1, 2015. Under the terms of the program, Mr. Teel's Performance Pay Program results were prorated based on the time he served at each company.

	Target Annual Performance Pay Program Opportunity (% of base salary)	Target Annual Performance Pay Program Opportunity ($)	Total Performance Factor (% of target)	Actual Annual Performance Pay Program Payout ($)
S. W. Connally, Jr.	60	255,671	153	391,000
X. Liu	45	123,125	148/157	188,996
R. S. Teel	45	123,402	157/148	184,693
J. R. Fletcher	45	108,211	157	169,891
W. E. Smith	40	81,822	157	128,461
B. C. Terry	45	126,119	157	198,007

Long-Term Performance-Based Compensation

2015 Long-Term Pay Program Highlights

- Changes in 2015
  - Moved away from granting stock options; 100% of award is in performance shares subject to achievement of performance goals over a three-year performance period
  - Expanded performance goals to include three performance measurements (TSR, EPS, and ROE)
- Performance Shares
  - Represents 100% of long-term target value
    - TSR relative to industry peers (50%)
    - Cumulative three-year EPS (25%)
    - Equity-weighted ROE (25%)
  - Three-year performance period from 2015 through 2017
  - Performance results can range from 0% to 200% of target
  - Paid in Common Stock at the end of the performance period; accrued dividends only received if and when award is earned

Since 2010, the long-term performance-based compensation program has included two components: stock options and performance shares. In early 2015, the Compensation Committee made some changes to the long-term performance-based compensation program that followed from the focus on continuously refining the executive compensation program to more effectively align executive pay with performance and reflect best compensation practices. Beginning with the 2015 grant, the Compensation Committee moved away from granting stock options and shifted the long-term equity award to 100% performance shares. The new structure maintains the three-year performance cycle but expands the performance metrics from one to three metrics: relative TSR (50% weighting), cumulative three-year EPS (25% weighting), and equity-weighted ROE (25% weighting).

2015-2017 Performance Share Program Grant

Performance shares are denominated in units, meaning no actual shares are issued on the grant date. A grant date fair value per unit was determined. For the portion of the grant attributable to the relative TSR goal, the value per unit was $46.43. For the portion of the grant attributable to the cumulative three-year EPS and equity-weighted ROE goals, the value per unit was $47.79. A target number of performance shares are granted to a participant, based on the total target value as determined as a percentage of a participant's base salary, which varies by grade level. The total target value for performance share units is divided by the value per unit to determine the number of performance share units granted to each participant, including the named executive officers. Each performance share unit represents one share of Common Stock.

The following table shows the grant date fair value and target number of the long-term equity incentive awards granted in 2015.

	Target Value (% of base salary)	Relative TSR (50%)		Cumulative EPS (25%)		Equity-Weighted ROE (25%)		Total Long-Term Grant	
		Grant Date Fair Value ($)	Target Number of Shares (#)	Grant Date Fair Value ($)	Target Number of Shares (#)	Grant Date Fair Value ($)	Target Number of Shares (#)	Grant Date Fair Value ($)	Target Number of Shares (#)
S. W. Connally, Jr.	130	276,955	5,965	138,495	2,898	138,495	2,898	553,946	11,761
X. Liu	60	77,445	1,668	38,710	810	38,710	810	154,865	3,288
R. S. Teel	60	78,327	1,687	39,188	820	39,188	820	156,703	3,327
J. R. Fletcher	60	72,152	1,554	36,081	755	36,081	755	144,315	3,064
W. E. Smith	40	40,905	881	20,454	428	20,454	428	81,813	1,737
B. C. Terry	60	84,085	1,811	42,055	880	42,055	880	168,195	3,571

The award includes three performance measures for the 2015-2017 performance period: relative TSR (50% weighting), cumulative three-year EPS (25% weighting), and equity-weighted ROE (25% weighting).

Goal	What it Measures	Why it's Important	How it's Calculated
Relative TSR	Stock price performance plus dividends relative to peer companies	Aligns employee pay with investor returns relative to peers	(Common Stock price at end of year 3 - common stock price at start of year 1 + dividends paid and reinvested) / Common Stock price at start of year 1 Result compared to similar calculation for peer group
Cumulative EPS	Cumulative EPS over the three-year performance period	Aligns employee pay with Southern Company's earnings growth	EPS Year 1 + EPS Year 2 + EPS Year 3 = Cumulative EPS Result
Equity-Weighted ROE	Equity-weighted ROE of the traditional operating companies	Aligns employee pay with Southern Company's ability to maximize return on capital invested	Average equity-weighted ROE of each traditional operating company during three-year performance period multiplied by the average equity weighting of each during the period

For each of the performance measures, a threshold, target and maximum goal was set at the beginning of the performance period.

	Relative TSR Performance (50% weighting)	Cumulative EPS Performance (25% weighting)	Equity-Weighted ROE Performance (25% weighting)	Payout (% of Performance Share Units Paid)
Maximum	90th percentile or higher	$9.16	5.9%	200%
Target	50th percentile	$8.66	5.1%	100%
Threshold	10th percentile	$8.16	4.7%	0%

The EPS and ROE goals are also both subject to a credit quality threshold requirement that encourages the maintenance of adequate credit ratings to provide an attractive return to investors. If the primary credit rating falls below investment grade at the end of the three-year performance period, the payout for the EPS and ROE goals will be reduced to zero.

Total stockholder return is measured relative to a peer group of companies that are believed to be most similar to Southern Company in both business model and investors. The peer group is subject to change based on merger and acquisition activity.

TSR Performance Share Peer Group for 2015 - 2017 Performance Period

Alliant Energy Corporation	OGE Energy Corporation
Ameren Corporation	Pepco Holdings, Inc.
American Electric Power Company, Inc.	PG&E Corporation
CMS Energy Corporation	Pinnacle West Capital Corporation
Consolidated Edison, Inc.	PPL Corporation
DTE Energy Company	SCANA Corporation
Duke Energy Corporation	Westar Energy Inc.
Edison International	Wisconsin Energy Corporation
Entergy Corporation	Xcel Energy Inc.
Eversource Energy	

Other Details about the Program

Performance shares are not earned until the end of the three-year performance period and after certification of the results by the Compensation Committee. A participant can earn from 0% to 200% of the target number of performance shares granted at the beginning of the performance period based solely on achievement of the performance goals over the three-year performance period. Dividend equivalents are credited during the three-year performance period but are only paid out if and when the award is earned. If no performance shares are earned, then no dividends are paid out. Payout for performance between points will be interpolated on a straight-line basis.

A participant who terminates employment, other than due to retirement or death, forfeits all unearned performance shares. Participants who retire during the performance period will receive the full amount of performance shares actually earned at the end of the three-year period. Performance shares will be prorated based on the number of months employed during the performance period for a participant who dies during the performance period.

The Compensation Committee retains the discretion to approve adjustments in determining actual performance goal achievement.

2013-2015 Payouts

Performance share grants were made in 2013 with a three-year performance period that ended on December 31, 2015. Based on Southern Company's TSR achievement relative to that of the Philadelphia Utility Index (55% payout) and the custom peer group (0% payout), the payout percentage was 28% of target, which is the average of the results for the two peer groups.

Philadelphia Utility Index		
AEP	DTE	Exelon
AES	Duke	First Energy
Ameren	Edison	NextEra
CenterPoint	El Paso Electric	PG&E
ConEd	Entergy	PSEG
Covanta	Eversource Energy	Xcel
Dominion		

Custom Peer Group	
AEP	Edison
Alliant Energy	Eversource Energy
Ameren	PG&E
CMS	Pinnacle West
ConEd	Scana
DTE	Wisconsin Energy
Duke	Xcel

Actual payouts were significantly less than the target grant date fair value due to below-target relative TSR performance.

	Target Performance Shares (#)	Target Value of Performance Shares ($)	Performance Shares Earned (#)	Value of Performance Shares Earned [(1)] ($)
S. W. Connally, Jr.	7,235	293,018	2,026	94,797
X. Liu	1,299	52,610	364	17,032
R. S. Teel	2,188	88,614	613	28,682
J. R. Fletcher	1,209	48,965	339	15,862
W. E. Smith	650	26,325	182	8,516
B. C. Terry	2,348	95,094	657	30,741

(1) Calculated using a stock price of $46.79, which was the closing price on December 31, 2015, the date the performance shares vested.

Timing of Performance-Based Compensation

The establishment of performance-based compensation goals and the granting of equity awards are not timed to coincide with the release of material, non-public information.

Southern Excellence Awards

Mr. Teel received a discretionary award in the amount of $5,000 while employed at SCS in recognition of his leadership and superior performance related to due diligence activities performed in connection with the Merger.

Retirement and Severance Benefits

Certain post-employment compensation is provided to employees, including the named executive officers, consistent with Gulf Power's goal of providing market-based compensation and benefits.

Retirement Benefits

Substantially all employees of Gulf Power participate in the funded Pension Plan after completing one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. Gulf Power also provides unfunded benefits that count salary and annual Performance Pay Program payouts that are ineligible to be counted under the Pension Plan. See the Pension Benefits table and accompanying information for more pension-related benefits information.

Gulf Power and its affiliates also provide supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers. Gulf Power has had a supplemental retirement agreement (SRA) with Ms. Terry since 2010. Prior to her employment with the Southern Company system, Ms. Terry provided legal services to Southern Company's subsidiaries. Ms. Terry's agreement provides retirement benefits as if she was employed an additional 10 years. Ms. Terry must remain employed at Gulf Power or an affiliate of Gulf Power for 10 years from the effective date of the SRA before vesting in the benefits. This agreement provides a benefit which recognizes the expertise she brought to Gulf Power and provides a strong retention incentive to remain with Gulf Power, or one of its affiliates, for the vesting period and beyond.

Gulf Power also provides the Deferred Compensation Plan, which is an unfunded plan that permits participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, disability, death, or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the Deferred Compensation Plan.

Change-in-Control Protections

Change-in-control protections, including severance pay and, in some situations, vesting or payment of long-term performance-based awards, are provided upon a change in control of Southern Company or Gulf Power coupled with an involuntary termination not for cause or a voluntary termination for “Good Reason.” This means there is a “double trigger” before severance benefits are paid; *i.e.,* there must be both a change in control and a termination of employment. Severance payment amounts are two times salary plus target Performance Pay Program opportunity for Mr. Connally and one times salary plus Performance Pay Program opportunity for the other named executive officers. No excise tax gross-up would be provided. Change-in-control protections allow executive officers to focus on potential transactions that are in the best interest of shareholders.

Perquisites

Gulf Power provides limited perquisites to its executive officers, including the named executive officers, consistent with Gulf Power's goal of providing market-based compensation and benefits. The perquisites provided in 2015, including amounts, are described in detail in the information accompanying the Summary Compensation Table. No tax assistance is provided on perquisites for the Chairman, President, and Chief Executive Officer, except on certain relocation-related benefits.

OTHER COMPENSATION POLICIES

Executive Stock Ownership Requirements

Officers of Gulf Power that are in a position of Vice President or above are subject to stock ownership requirements. All of the named executive officers are covered by the requirements. Ownership requirements further align the interest of officers and Southern Company's stockholders by promoting a long-term focus and long-term share ownership. The types of ownership arrangements counted toward the requirements are shares owned outright, those held in Southern Company-sponsored plans, and Common Stock accounts in the Deferred Compensation Plan and the Supplemental Benefit Plan. One-third of vested Southern Company stock options may be counted, but, if so, the ownership requirement is doubled. The ownership requirement is reduced by one-half at age 60.

The requirements are expressed as a multiple of base salary as shown below.

	Multiple of Salary without Counting Stock Options	Multiple of Salary Counting 1/3 of Vested Options
S. W. Connally, Jr.	3 Times	6 Times
X. Liu	2 Times	4 Times
R. S. Teel	2 Times	4 Times
J. R. Fletcher	2 Times	4 Times
W. E. Smith	1 Times	2 Times
B. C. Terry	2 Times	4 Times

Newly-elected officers have approximately five years from the date of their election to meet the applicable ownership requirement. Newly-promoted officers have approximately five years from the date of their promotion to meet the increased ownership requirement. All of the named executive officers are meeting their respective ownership requirements.

Policy on Recovery of Awards

Southern Company's Omnibus Incentive Compensation Plan provides that, if Southern Company or Gulf Power is required to prepare an accounting restatement due to material noncompliance as a result of misconduct, and if an executive officer of Gulf Power knowingly or grossly negligently engaged in or failed to prevent the misconduct or is subject to automatic forfeiture under the Sarbanes-Oxley Act of 2002, the executive officer must repay Southern Company the amount of any payment in settlement of awards earned or accrued during the 12-month period following the first public issuance or filing that was restated.

Policy Regarding Hedging and Pledging of Common Stock

Southern Company's insider trading policy provides that employees, officers, and directors will not trade Southern Company options on the options market and will not engage in short sales. In early 2016, Southern Company added a "no pledging" provision to the insider trading policy that prohibits pledging of Common Stock for all Southern Company directors and executive officers, including the Gulf Power President and Chief Executive Officer.

COMPENSATION COMMITTEE REPORT

The Compensation Committee met with management to review and discuss the CD&A. Based on such review and discussion, the Compensation Committee recommended to the Southern Company Board of Directors that the CD&A be included in Gulf Power's Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

Members of the Compensation Committee:

Henry A. Clark III, Chair
David J. Grain
Veronica M. Hagen
William G. Smith, Jr.
Steven R. Specker

SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received or earned in 2013, 2014, and 2015 by the named executive officers, except as noted below.

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation ($) (i)	Total ($) (j)
S. W. Connally, Jr.	2015	420,758	—	553,946	—	391,000	160,338	30,485	1,556,527
President, Chief Executive Officer, and	2014	393,907	—	310,606	207,086	339,302	496,800	25,948	1,773,649
Director	2013	372,977	—	293,018	195,363	164,557	54,607	25,602	1,106,124
X. Liu	2015	265,380	—	154,865	—	188,996	59,936	283,417	952,594
Vice President and Chief Financial Officer									
R. S. Teel	2015	266,977	5,000	156,703	—	184,693	35,467	253,830	902,670
Former Vice President and Chief Financial	2014	252,110	—	91,260	60,841	161,989	157,002	17,166	740,368
Officer	2013	244,903	—	88,614	59,101	80,895	—	17,004	490,517
J. R. Fletcher	2015	238,711	—	144,315	—	169,891	48,436	120,417	721,770
Vice President	2014	224,547	25,045	50,679	33,801	149,633	273,148	89,971	846,824
W. E. Smith	2015	203,401	—	81,813	—	128,461	42,181	144,040	599,896
Vice President									
B. C. Terry	2015	278,682	—	168,195	—	198,007	34,345	19,421	698,650
Vice President	2014	270,543	—	97,904	65,287	173,833	245,578	17,664	870,809
	2013	262,809	—	95,094	63,419	86,809	—	16,735	524,866

Column (a)

Ms. Liu and Mr. Smith first became named executive officers in 2015.

Column (d)

The amount shown for 2015 for Mr. Teel represents a Southern Excellence Award as described in the CD&A.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2015. Rather, as required by applicable rules of the SEC, this column reports the aggregate grant date fair value of performance shares granted in 2015. The value reported is based on the probable outcome of the performance conditions as of the grant date, using a Monte Carlo simulation model (50% of grant value) and the closing price of Common Stock on the grant date (50% of grant value). No amounts will be earned until the end of the three-year performance period on December 31, 2017. The value then can be earned based on performance ranging from 0 to 200%, as established by the Compensation Committee. The aggregate grant date fair value of the performance shares granted in 2015 to Mses. Liu and Terry and Messrs. Connally, Teel, Fletcher, and Smith, assuming that the highest level of performance is achieved, is $309,730, $336,390, $1,107,892, $313,406, $288,630, and $163,626, respectively (200% of the amount shown in the table). See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (f)

Stock options were not granted in 2015. This column reports the aggregate grant date fair value of stock options granted in 2013 and 2014.

Column (g)

The amounts in this column are the payouts under the annual Performance Pay Program. The amount reported for 2015 is for the one-year performance period that ended on December 31, 2015. The Performance Pay Program is described in detail in the CD&A.

Column (h)

This column reports the aggregate change in the actuarial present value of each named executive officer's accumulated benefit under the Pension Plan and the supplemental pension plans (collectively, Pension Benefits) as of December 31, 2013, 2014, and 2015. The Pension Benefits as of each measurement date are based on the named executive officer's age, pay, and service accruals and the plan provisions applicable as of the measurement date. The actuarial present values as of each measurement date reflect the assumptions Gulf Power selected for cost purposes as of that measurement date; however, the named executive officers were assumed to remain employed at Gulf Power or any Southern Company subsidiary until their benefits commence at the pension plans' stated normal retirement date, generally age 65. As a result, the amounts in column (h) related to Pension Benefits represent the combined impact of several factors: growth in the named executive officer's Pension Benefits over the measurement year; impact on the total present values of one year shorter discounting period due to the named executive officer being one year closer to normal retirement; impact on the total present values attributable to changes in assumptions from measurement date to measurement date; and impact on the total present values attributable to plan changes between measurement dates.

For more information about the Pension Benefits and the assumptions used to calculate the actuarial present value of accumulated benefits as of December 31, 2015, see the information following the Pension Benefits table. This column also reports above-market earnings on deferred compensation under the Deferred Compensation Plan (DCP). However, there were no above-market earnings on deferred compensation in the years reported.

Column (i)

This column reports the following items: perquisites; tax reimbursements; employer contributions to the Southern Company Employee Savings Plan (ESP), which is a tax-qualified defined contribution plan intended to meet requirements of Section 401(k) of the Internal Revenue Code; and employer contributions under the Southern Company Supplemental Benefit Plan (Non-Pension Related) (SBP). The SBP is described more fully in the information following the Nonqualified Deferred Compensation table.

The amounts reported for 2015 are itemized below.

	Perquisites ($)	**Tax Reimbursements ($)**	**ESP ($)**	**SBP ($)**	**Total ($)**
S. W. Connally, Jr.	9,069	—	13,472	7,944	30,485
X. Liu	257,862	12,281	13,255	19	283,417
R. S. Teel	205,087	35,127	13,515	101	253,830
J. R. Fletcher	99,741	8,502	12,174	—	120,417
W. E. Smith	131,102	2,558	8,817	1,563	144,040
B. C. Terry	7,055	189	11,479	698	19,421

Description of Perquisites

Personal Financial Planning is provided for most officers of Gulf Power, including all of the named executive officers. Gulf Power pays for the services of a financial planner on behalf of the officers, up to a maximum amount of $8,700 per year, after the initial year that the benefit is provided. In the initial year, the allowed amount is $15,000. Gulf Power also provides a five-year allowance of $6,000 for estate planning and tax return preparation fees.

Relocation Benefits are provided to cover the costs associated with geographic relocation. In 2015, Ms. Liu received relocation-related benefits in the amount of $248,985 in connection with her 2015 relocation from Atlanta, Georgia to Pensacola, Florida. In 2015, Mr. Teel received relocation-related benefits in the amount of $196,980 in connection with his 2015 relocation from Pensacola to Birmingham, Alabama. In 2015, Mr. Fletcher received relocation-related benefits in the amount of $92,950 in connection with his 2014 relocation from Atlanta to Pensacola. In 2015, Mr. Smith received relocation-related benefits in the amount of $127,866 in connection with his 2014 relocation from Athens, Georgia to Pensacola. These amounts were for the shipment of household goods, incidental expenses related to the moves, and home sale and home repurchase assistance. Also, as provided in Gulf Power's relocation policy, tax assistance is provided on the taxable relocation benefits. If the named executive officer terminates within two years of relocation, these amounts must be repaid.

Personal Use of Corporate Aircraft. The Southern Company system has aircraft that are used to facilitate business travel. All flights on these aircraft must have a business purpose, except limited personal use that is associated with business travel is permitted for the President and Chief Executive Officer. Additionally, limited personal use related to relocation is permissible but must be approved. The amount reported for such personal use is the incremental cost of providing the benefit, primarily fuel costs. Also, if seating is available, Southern Company permits a spouse or other family member to accompany an employee on a flight. However, because in such cases the aircraft is being used for a business purpose, there is no incremental cost associated with the family travel, and no amounts are included for such travel. Any additional expenses incurred that are related to family travel are included.

In connection with Ms. Liu's relocation from Atlanta to Pensacola, Mr. Connally approved personal use of the corporate aircraft for one round-trip flight per month for six months. The perquisite amount shown for Ms. Liu includes $2,380 for this approved use of corporate aircraft. In connection with his relocation from Pensacola to Birmingham, Mr. Teel was approved for limited personal use of the corporate aircraft by the Chief Operating Officer of Southern Company. The perquisite amount shown for Mr. Teel includes $2,090 for this approved use of corporate aircraft.

Other Miscellaneous Perquisites. The amount included reflects the full cost to Gulf Power of providing the following items: personal use of company-provided tickets for sporting and other entertainment events and gifts distributed to and activities provided to attendees at company-sponsored events.

GRANTS OF PLAN-BASED AWARDS IN 2015

This table provides information on equity grants made and goals established for future payouts under the performance-based compensation programs during 2015 by the Compensation Committee.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			
Name (a)	**Grant Date (b)**	**Threshold ($) (c)**	**Target ($) (d)**	**Maximum ($) (e)**	**Threshold (#) (f)**	**Target (#) (g)**	**Maximum (#) (h)**	**Grant Date Fair Value of Stock and Option Awards ($) (i)**
S. W. Connally, Jr.		2,557	255,671	511,343				
	2/9/2015				117	11,761	23,522	553,946
X. Liu		1,231	123,125	246,250				
	2/9/2015				32	3,288	6,576	154,865
R. S. Teel		1,234	123,402	246,804				
	2/9/2015				33	3,327	6,654	156,703
J. R. Fletcher		1,082	108,211	216,423				
	2/9/2015				30	3,064	6,128	144,315
W. E. Smith		818	81,822	163,644				
	2/9/2015				17	1,737	3,474	81,813
B. C. Terry		1,261	126,119	252,237				
	2/9/2015				35	3,571	7,142	168,195

Columns (c), (d), and (e)

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2015 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. The actual amounts earned are disclosed in the Summary Compensation Table. The amounts shown for Ms. Liu and Mr. Teel reflect the increases in salary and annual Performance Pay Program opportunity each received after their respective promotions in 2015.

Columns (f), (g), and (h)

These columns reflect the performance shares granted to the named executive officers in 2015 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. Earned performance shares and accrued dividends will be paid out in Common Stock following the end of the 2015 through 2017 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

Column (i)

This column reflects the aggregate grant date fair value of the performance shares granted in 2015. For performance shares, 50% of the value is based on the probable outcome of the performance conditions as of the grant date using a Monte Carlo simulation model ($46.43), while the other 50% is based on the closing price of the Common Stock on the grant date ($47.79). The assumptions used in calculating these amounts are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein.

OUTSTANDING EQUITY AWARDS AT 2015 FISCAL YEAR-END

This table provides information pertaining to all outstanding stock options and stock awards (performance shares) held by or granted to the named executive officers as of December 31, 2015.

Name (a)	Option Awards				Stock Awards	
Name (a)	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Option Exercise Price ($) (d)	Option Expiration Date (e)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (f)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (g)
S. W. Connally, Jr.	14,392	0	31.39	02/16/2019		
	16,100	0	37.97	02/14/2021		
	16,053	0	44.42	02/13/2022		
	44,603	22,302	44.06	02/11/2023		
	31,377	62,753	41.28	02/10/2024		
					8,274	387,140
					12,354	578,044
X. Liu	10,079	0	37.97	02/14/2021		
	9,976	0	44.42	02/13/2022		
	8,011	4,005	44.06	02/11/2023		
	8,798	17,595	41.28	02/10/2024		
					2,320	108,553
					3,452	161,519
R. S. Teel	9,078	0	35.78	02/18/2018		
	9,332	0	31.39	02/16/2019		
	9,629	0	31.17	02/15/2020		
	16,774	0	37.97	02/14/2021		
	16,926	0	44.42	02/13/2022		
	13,493	6,747	44.06	02/11/2023		
	9,219	18,436	41.28	02/10/2024		
					2,431	113,746
					3,494	163,484
J. R.Fletcher	3,376	0	37.97	02/14/2021		
	9,371	0	44.42	02/13/2022		
	7,456	3,728	44.06	02/11/2023		
	5,122	10,242	41.28	02/10/2024		
					1,350	63,167
					3,218	150,570
W. E. Smith	5,037	0	44.42	2/13/2022		
	4,007	2,004	44.06	2/11/2023		
	2,838	5,676	41.28	2/10/2024		
					748	34,999
					1,823	85,298
B. C. Terry	18,574	0	37.97	02/14/2021		
	18,163	0	44.42	02/13/2022		
	14,479	7,240	44.06	02/11/2023		
	9,892	19,784	41.28	02/10/2024		
					2,608	122,028
					3,750	175,463

Columns (b), (c), (d), and (e)

Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2007 through 2012 with expiration dates from 2017 through 2022 were fully vested as of December 31, 2015. The options granted in 2013 and 2014 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2013	February 11, 2023	February 11, 2016
2014	February 10, 2024	February 10, 2017

Options also fully vest upon death, total disability, or retirement and expire three years following death or total disability or five years following retirement, or on the original expiration date if earlier. Please see Potential Payments upon Termination or Change in Control for more information about the treatment of stock options under different termination and change-in-control events.

Columns (f) and (g)

In accordance with SEC rules, column (f) reflects the target number of performance shares that can be earned at the end of each three-year performance period (December 31, 2016 and 2017) that were granted in 2014 and 2015, respectively. The number of shares reflected in column (f) for the performance shares granted in 2015 also reflects the deemed reinvestment of dividends on the target number of performance shares. The ultimate number of dividends a named executive will earn at the end of the performance period ultimately depends on Southern Company performance. If no performance shares are paid out, no dividends will be paid out.

The performance shares granted for the 2013 through 2015 performance period vested on December 31, 2015 and are shown in the Option Exercises and Stock Vested in 2015 table below. The value in column (g) is derived by multiplying the number of shares in column (f) by the Common Stock closing price on December 31, 2015 ($46.79). The ultimate number of shares earned, if any, will be based on the actual performance results at the end of each respective performance period. See further discussion of performance shares in the CD&A. See also Potential Payments upon Termination or Change in Control for more information about the treatment of performance shares under different termination and change-in-control events.

OPTION EXERCISES AND STOCK VESTED IN 2015

	Option Awards		Stock Awards	
Name (a)	**Number of Shares Acquired on Exercise (#) (b)**	**Value Realized on Exercise ($) (c)**	**Number of Shares Acquired on Vesting (#) (d)**	**Value Realized on Vesting ($) (e)**
S. W. Connally, Jr.	8,521	76,012	2,026	94,797
X. Liu	—	—	364	17,032
R. S. Teel	—	—	613	28,682
J. R. Fletcher	—	—	339	15,862
W. E. Smith	—	—	182	8,516
B. C. Terry	12,918	159,464	657	30,741

Columns (b) and (c)

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2015 and column (c) reflects the value realized. The value realized is the difference in the market price over the exercise price on the exercise date.

Columns (d) and (e)

Column (d) includes the performance shares awarded for the 2013 through 2015 performance period that vested on December 31, 2015. The value reflected in column (e) is derived by multiplying the number of shares in column (d) by the market value of the underlying shares on the vesting date ($46.79).

PENSION BENEFITS AT 2015 FISCAL YEAR-END

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
	Pension Plan	24.17	564,283	0
	SBP-P	24.17	600,176	0
S.W. Connally, Jr.	SERP	24.17	396,421	0
	Pension Plan	15.92	364,469	0
	SBP-P	15.92	76,721	0
X. Liu	SERP	15.92	130,872	0
	Pension Plan	15.33	343,793	0
	SBP-P	15.33	65,959	0
R. S. Teel	SERP	15.33	113,213	0
	Pension Plan	25.58	590,440	0
	SBP-P	25.58	127,297	0
J. R. Fletcher	SERP	25.58	194,480	0
	Pension Plan	28.17	619,105	0
	SBP-P	28.17	57,930	0
W. E. Smith	SERP	28.17	165,857	0
	Pension Plan	13.50	324,159	0
	SBP-P	13.50	75,303	0
	SERP	13.50	103,371	0
B. C. Terry	SRA	10.00	406,099	0

Pension Plan

The Pension Plan is a tax-qualified, funded plan. It is Southern Company's primary retirement plan. Substantially all employees participate in this plan after one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. The plan benefit equals the greater of amounts computed using a "1.7% offset formula" and a "1.25% formula," as described below. Benefits are limited to a statutory maximum.

The 1.7% offset formula amount equals 1.7% of final average pay times years of participation less an offset related to Social Security benefits. The offset equals a service ratio times 50% of the anticipated Social Security benefits in excess of $4,200. The service ratio adjusts the offset for the portion of a full career that a participant has worked. The highest three rates of pay out of a participant's last 10 calendar years of service are averaged to derive final average pay. The rates of pay considered for this formula are the base salary rates with no adjustments for voluntary deferrals after 2008. A statutory limit restricts the amount considered each year; the limit for 2015 was $265,000.

The 1.25% formula amount equals 1.25% of final average pay times years of participation. For this formula, the final average pay computation is the same as above, but annual performance-based compensation earned each year is added to the base salary rates of pay.

Early retirement benefits become payable once plan participants have, during employment, attained age 50 and completed 10 years of participation. Participants who retire early from active service receive benefits equal to the amounts computed using the same formulas employed at normal retirement. However, a 0.3% reduction applies for each month (3.6% for each year) prior to normal retirement that participants elect to have their benefit payments commence. For example, 64% of the formula benefits are payable starting at age 55. As of December 31, 2015, Mses. Liu and Terry and Messrs. Connally, Fletcher, and Teel were not retirement-eligible.

The Pension Plan's benefit formulas produce amounts payable monthly over a participant's post-retirement lifetime. At retirement, plan participants can choose to receive their benefits in one of seven alternative forms of payment. All forms pay benefits monthly over the lifetime of the retiree or the joint lifetimes of the retiree and a spouse. A reduction applies if a retiring participant chooses a payment form other than a single life annuity. The reduction makes the value of the benefits paid in the form chosen comparable to what it would have been if benefits were paid as a single life annuity over the retiree's life.

Participants vest in the Pension Plan after completing five years of service. As of December 31, 2015, all of the named executive officers are vested in their Pension Plan benefits. Participants who terminate employment after vesting can elect to have their pension benefits commence at age 50 if they participated in the Pension Plan for 10 years. If such an election is made, the early retirement reductions that apply are actuarially determined factors and are larger than 0.3% per month.

If a participant dies while actively employed and is either age 50 or vested in the Pension Plan as of date of death, benefits will be paid to a surviving spouse. A survivor's benefit equals 45% of the monthly benefit that the participant had earned before his or her death. Payments to a surviving spouse of a participant who could have retired will begin immediately. Payments to a survivor of a participant who was not retirement-eligible will begin when the deceased participant would have attained age 50.

After commencing, survivor benefits are payable monthly for the remainder of a survivor's life. Participants who are eligible for early retirement may opt to have an 80% survivor benefit paid if they die; however, there is a charge associated with this election.

If participants become totally disabled, periods that Social Security or employer-provided disability income benefits are paid will count as service for benefit calculation purposes. The crediting of this additional service ceases at the point a disabled participant elects to commence retirement payments. Outside of this extra service crediting, the normal Pension Plan provisions apply to disabled participants.

The Southern Company Supplemental Benefit Plan (Pension-Related) (SBP-P)

The SBP-P is an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees any benefits that the Pension Plan cannot pay due to statutory pay/benefit limits. The SBP-P's vesting and early retirement provisions mirror those of the Pension Plan. Its disability provisions mirror those of the Pension Plan but cease upon a participant's separation from service.

The amounts paid by the SBP-P are based on the additional monthly benefit that the Pension Plan would pay if the statutory limits and pay deferrals were ignored. When a SBP-P participant separates from service, vested monthly benefits provided by the benefit formulas are converted into a single sum value. It equals the present value of what would have been paid monthly for an actuarially determined average post-retirement lifetime. The discount rate used in the calculation is based on the 30-year U.S. Treasury yields for the September preceding the calendar year of separation, but not more than six percent.

Vested participants terminating prior to becoming eligible to retire will be paid their single sum value as of September 1 following the calendar year of separation. If the terminating participant is retirement-eligible, the single sum value will be paid in 10 annual installments starting shortly after separation. The unpaid balance of a retiree's single sum will be credited with interest at the prime rate published in *The Wall Street Journal* . If the separating participant is a "key man" under Section 409A of the Internal Revenue Code, the first installment will be delayed for six months after the date of separation.

If a SBP-P participant dies after becoming vested in the Pension Plan, the spouse of the deceased participant will receive the installments the participant would have been paid upon retirement. If a vested participant's death occurs prior to age 50, the installments will be paid to a spouse as if the participant had survived to age 50.

The Southern Company Supplemental Executive Retirement Plan (SERP)

The SERP is also an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees additional benefits that the Pension Plan and the SBP-P would pay if the 1.7% offset formula calculations reflected a portion of annual performance-based compensation. To derive the SERP benefits, a final average pay is determined reflecting participants' base rates of pay and their annual performance-based compensation amounts, whether or not deferred, to the extent they exceed 15% of those base rates (ignoring statutory limits). This final average pay is used in the 1.7% offset formula to derive a gross benefit. The Pension Plan and the SBP-P benefits are subtracted from the gross benefit to calculate the SERP benefit. The SERP's early retirement, survivor benefit, disability, and form of payment provisions mirror the SBP-P's provisions. However, except upon a change in control, SERP benefits do not vest until participants retire, so no benefits are paid if a participant terminates prior to becoming retirement-eligible. More information about vesting and payment of SERP benefits following a change in control is included under Potential Payments upon Termination or Change-in-Control.

Supplemental Retirement Agreements (SRA)

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers and generally provide for additional retirement benefits by giving credit for years of employment prior to employment with Gulf Power or one of its affiliates. These supplemental retirement benefits are also unfunded and not tax-qualified. Information about the SRA with Ms. Terry is included in the CD&A.

Pension Benefit Assumptions

The following assumptions were used in the present value calculations for all pension benefits:

- Discount rate - 4.70% Pension Plan and 4.14% supplemental plans as of December 31, 2015,
- Retirement date - Normal retirement age (65 for all named executive officers),
- Mortality after normal retirement - Adjusted RP-2014 with generational projections,
- Mortality, withdrawal, disability, and retirement rates prior to normal retirement - None,
- Form of payment for Pension Benefits:
    - Male retirees: 25% single life annuity; 25% level income annuity; 25% joint and 50% survivor annuity; and 25% joint and 100% survivor annuity,
    - Female retirees: 50% single life annuity; 30% level income annuity; 15% joint and 50% survivor annuity; and 5% joint and 100% survivor annuity,
- Spouse ages - Wives two years younger than their husbands,
- Annual performance-based compensation earned but unpaid as of the measurement date - 130% of target opportunity percentages times base rate of pay for year amount is earned, and
- Installment determination - 3.75% discount rate for single sum calculation and 4.25% prime rate during installment payment period.

For all of the named executive officers, the number of years of credited service for the Pension Plan, the SBP-P, and the SERP is one year less than the number of years of employment.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2015 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
S. W. Connally, Jr.	—	7,943	8,125	—	143,905
X. Liu	—	19	4,274	—	133,018
R. S. Teel	—	101	1	—	264
J. R. Fletcher	—	—	—	—	—
W. E. Smith	49,139	1,563	2,846	—	101,063
B. C. Terry	86,917	698	7,771	—	365,783

Southern Company provides the DCP, which is designed to permit participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the DCP.

Participants have two options for the deemed investments of the amounts deferred - the Stock Equivalent Account and the Prime Equivalent Account. Under the terms of the DCP, participants are permitted to transfer between investments at any time.
The amounts deferred in the Stock Equivalent Account are treated as if invested at an equivalent rate of return to that of an actual investment in Common Stock, including the crediting of dividend equivalents as such are paid by Southern Company from time to time. It provides participants with an equivalent opportunity for the capital appreciation (or loss) and income of that of a Southern Company stockholder. During 2015, the rate of return in the Stock Equivalent Account was -0.01%.

Alternatively, participants may elect to have their deferred compensation deemed invested in the Prime Equivalent Account which is treated as if invested at a prime interest rate compounded monthly, as published in *The Wall Street Journal* as the base rate on corporate loans posted as of the last business day of each month by at least 75% of the United States' largest banks. The interest rate earned on amounts deferred during 2015 in the Prime Equivalent Account was 3.32%.

Column (b)

This column reports the actual amounts of compensation deferred under the DCP by each named executive officer in 2015. The amount of salary deferred by the named executive officers, if any, is included in the Salary column in the Summary Compensation Table. The amounts of performance-based compensation deferred in 2015 were the amounts that were earned as of December 31, 2014 but not payable until the first quarter of 2015. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2015, but not payable until early 2016. These deferred amounts may be distributed in a lump sum or in up to 10 annual installments at termination of employment or in a lump sum at a specified date, at the election of the participant.

Column (c)

This column reflects contributions under the SBP. Under the Internal Revenue Code, employer-matching contributions are prohibited under the ESP on employee contributions above stated limits in the ESP, and, if applicable, above legal limits set forth in the Internal Revenue Code. The SBP is a nonqualified deferred compensation plan under which contributions are made that are prohibited from being made in the ESP. The contributions are treated as if invested in Common Stock and are payable in cash upon termination of employment in a lump sum or in up to 20 annual installments, at the election of the participant. The amounts reported in this column also were reported in the All Other Compensation column in the Summary Compensation Table.

Column (d)

This column reports earnings or losses on both compensation the named executive officers elected to defer and on employer contributions under the SBP.

Column (f)

This column includes amounts that were deferred under the DCP and contributions under the SBP in prior years and reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K. The following chart shows the amounts reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K.

Name	**Amounts Deferred under the DCP Prior to 2015 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)**	**Employer Contributions under the SBP Prior to 2015 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)**	**Total ($)**
S. W. Connally, Jr.	31,742	18,887	50,629
X. Liu	—	—	—
R. S. Teel	—	—	—
J. R. Fletcher	—	—	—
W. E. Smith	—	—	—
B. C. Terry	287,157	1,488	288,645

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

This section describes and estimates payments that could be made to the named executive officers serving as of December 31, 2015 under different termination and change-in-control events. The estimated payments would be made under the terms of Southern Company's compensation and benefit program or the change-in-control severance program. All of the named executive officers are participants in Southern Company's change-in-control severance program for officers. The amount of potential payments is calculated as if the triggering events occurred as of December 31, 2015 and assumes that the price of Common Stock is the closing market price on December 31, 2015.

Description of Termination and Change-in-Control Events
The following charts list different types of termination and change-in-control events that can affect the treatment of payments under the compensation and benefit programs. No payments are made under the change-in-control severance program unless, within two years of the change in control, the named executive officer is involuntarily terminated or voluntarily terminates for Good Reason. (See the description of Good Reason below.)

Traditional Termination Events

- Retirement or Retirement-Eligible - Termination of a named executive officer who is at least 50 years old and has at least 10 years of credited service.
- Resignation - Voluntary termination of a named executive officer who is not retirement-eligible.
- Lay Off - Involuntary termination of a named executive officer who is not retirement-eligible not for cause.
- Involuntary Termination - Involuntary termination of a named executive officer for cause. Cause includes individual performance below minimum performance standards and misconduct, such as violation of Gulf Power's Drug and Alcohol Policy.
- Death or Disability - Termination of a named executive officer due to death or disability.

Change-in-Control-Related Events
At the Southern Company or Gulf Power level:

- Southern Company Change-in-Control I - Consummation of an acquisition by another entity of 20% or more of Common Stock, or following consummation of a merger with another entity, Southern Company's stockholders own 65% or less of the entity surviving the merger.
- Southern Company Change-in-Control II - Consummation of an acquisition by another entity of 35% or more of Common Stock, or following consummation of a merger with another entity, Southern Company shareholders own less than 50% of Southern Company surviving the merger.
- Southern Company Does Not Survive Merger - Consummation of a merger or other event and Southern Company is not the surviving company or the Common Stock is no longer publicly traded.
- Gulf Power Change in Control - Consummation of an acquisition by another entity, other than another subsidiary of Southern Company, of 50% or more of the stock of Gulf Power, consummation of a merger with another entity and Gulf Power is not the surviving company, or the sale of substantially all the assets of Gulf Power.

At the employee level:

- Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason - Employment is terminated within two years of a change in control, other than for cause, or the employee voluntarily terminates for Good Reason. Good Reason for voluntary termination within two years of a change in control generally is satisfied when there is a material reduction in salary, performance-based compensation opportunity, or benefits; relocation of over 50 miles; or a diminution in duties and responsibilities.

T he following chart describes the treatment of different pay and benefit elements in connection with the Traditional Termination Events as described above.

Program	Retirement/ Retirement-Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Pension Benefits Plans	Benefits payable as described in the notes following the Pension Benefits table.	Same as Retirement.	Same as Retirement.	Same as Retirement.	Same as Retirement.
Annual Performance Pay Program	Prorated if retire before 12/31.	Same as Retirement.	Forfeit.	Same as Retirement.	Forfeit.
Stock Options	Vest; expire earlier of original expiration date or five years.	Vested options expire in 90 days; unvested are forfeited.	Same as Lay Off.	Vest; expire earlier of original expiration date or three years.	Forfeit.
Performance Shares	No proration if retirement prior to end of performance period. Will receive full amount actually earned.	Forfeit.	Forfeit.	Death - prorate for amount of time employed during performance period. Disability - not affected.	Forfeit.
Financial Planning Perquisite	Continues for one year.	Terminates.	Terminates.	Same as Retirement.	Terminates.
DCP	Payable per prior elections (lump sum or up to 10 annual installments).	Same as Retirement.	Same as Retirement.	Payable to beneficiary or participant per prior elections. Amounts deferred prior to 2005 can be paid as a lump sum per the benefit administration committee's discretion.	Same as Retirement.
SBP - non-pension related	Payable per prior elections (lump sum or up to 20 annual installments).	Same as Retirement.	Same as Retirement.	Same as the DCP.	Same as Retirement.

The following chart describes the treatment of payments under compensation and benefit programs under different change-in-control events, except the Pension Plan. The Pension Plan is not affected by change-in-control events.

Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Does Not Survive Merger or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Nonqualified Pension Benefits (except SRA)	All SERP-related benefits vest if participants vested in tax-qualified pension benefits; otherwise, no impact. SBP - pension- related benefits vest for all participants and single sum value of benefits earned to change-in-control date paid following termination or retirement.	Benefits vest for all participants and single sum value of benefits earned to the change-in-control date paid following termination or retirement.	Same as Southern Company Change-in-Control II.	Based on type of change-in-control event.
SRA	Not affected.	Not affected.	Not affected.	Vest.
Annual Performance Pay Program	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change in control, prorated at target performance level.	Same as Southern Company Change-in-Control I.	Prorated at target performance level.	If not otherwise eligible for payment, if the program is still in effect, prorated at target performance level.
Stock Options	Not affected.	Not affected.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
Performance Shares	Not affected.	Not affected.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
DCP	Not affected.	Not affected.	Not affected.	Not affected.
SBP	Not affected.	Not affected.	Not affected.	Not affected.
Severance Benefits	Not applicable.	Not applicable.	Not applicable.	One or two times base salary plus target annual performance-based pay.
Healthcare Benefits	Not applicable.	Not applicable.	Not applicable.	Up to five years participation in group healthcare plan plus payment of two or three years' premium amounts.
Outplacement Services	Not applicable.	Not applicable.	Not applicable.	Six months.

Potential Payments

This section describes and estimates payments that would become payable to the named executive officers upon a termination or change in control as of December 31, 2015 .

Pension Benefits
The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2015 under the Pension Plan, the SBP-P, the SERP, and, if applicable, an SRA are itemized in the following chart. The amounts shown under the Retirement column are amounts that would have become payable to the named executive officers that were retirement-eligible on December 31, 2015 and are the monthly Pension Plan benefits and the first of 10 annual installments from the SBP-P and the SERP. The amounts shown under the Resignation or Involuntary Termination column are the amounts that would have become payable to the named executive officers who were not retirement-eligible on December 31, 2015 and are the monthly Pension Plan benefits that would become payable as of the earliest possible date under the Pension Plan and the single sum value of benefits earned up to the termination date under the SBP-P, paid as a single payment rather than in 10 annual installments. Benefits under the SERP would be forfeited. The amounts shown that are payable to a spouse in the event of the death of the named executive officer are the monthly amounts payable to a spouse under the Pension Plan and the first of 10 annual installments from the SBP-P and the SERP.

The amounts in this chart are very different from the pension values shown in the Summary Compensation Table and the Pension Benefits table. Those tables show the present values of all the benefit amounts anticipated to be paid over the lifetimes of the named executive officers and their spouses. Those plans are described in the notes following the Pension Benefits table. Of the named executive officers, Mses. Liu and Terry and Messrs. Connally, Fletcher, and Teel were not retirement-eligible on December 31, 2015. The SRA for Ms. Terry contains an additional service requirement for benefit eligibility which was not met as of December 31, 2015. Therefore she was not eligible to receive retirement benefits under the agreement. However, death benefits would be paid to her surviving spouse.

Name		Retirement ($)	Resignation or Involuntary Termination ($)	Death (payments to a spouse) ($)
S. W. Connally, Jr.	Pension	n/a	2,318	3,807
	SBP-P	n/a	750,455	86,598
	SERP	n/a	—	57,199
X. Liu	Pension	n/a	1,441	2,367
	SBP-P	n/a	96,134	11,183
	SERP	n/a	—	19,076
R. S. Teel	Pension	n/a	1,437	2,360
	SBP-P	n/a	82,766	9,679
	SERP	n/a	—	16,614
J. R. Fletcher	Pension	n/a	2,093	3,438
	SBP-P	n/a	154,733	16,044
	SERP	n/a	—	24,512
W. E. Smith	Pension	3,700	All plans treated as retiring	3,398
	SBP-P	7,305		7,305
	SERP	20,914		20,914
B. C. Terry	Pension	n/a	1,296	2,129
	SBP-P	n/a	94,266	11,088
	SERP	n/a	—	15,221
	SRA	n/a	—	59,796

As described in the Change-in-Control chart, the only change in the form of payment, acceleration, or enhancement of the pension benefits is that the single sum value of benefits earned up to the change-in-control date under the SBP-P, the SERP, and the SRA could be paid as a single payment rather than in 10 annual installments. Also, the SERP benefits vest for participants who are not retirement-eligible upon a change in control. Estimates of the single sum payment that would have been made to the named executive officers, assuming termination as of December 31, 2015 following a change-in-control-related event, other than a Southern Company Change-in-Control I (which does not impact how pension benefits are paid), are itemized below. These amounts would be paid instead of the benefits shown in the Traditional Termination Events chart above; they are not paid in addition to those amounts.

Name	SBP-P ($)	SERP ($)	SRA ($)	Total ($)
S. W. Connally, Jr.	736,542	486,491	—	1,223,033
X. Liu	94,352	160,949	—	255,301
R. S. Teel	81,232	139,429	—	220,661
J. R. Fletcher	151,864	232,012	—	383,876
W. E. Smith	73,047	209,141	—	282,188
B. C. Terry	92,519	127,003	498,939	718,461

The pension benefit amounts in the tables above were calculated as of December 31, 2015 assuming payments would begin as soon as possible under the terms of the plans. Accordingly, appropriate early retirement reductions were applied. Any unpaid annual performance-based compensation was assumed to be paid at 1.30 times the target level. Pension Plan benefits were calculated assuming each named executive officer chose a single life annuity form of payment, because that results in the greatest monthly benefit. The single sum values were based on a 3.26 % discount rate .

Annual Performance Pay Program
The amount payable if a change in control had occurred on December 31, 2015 is the greater of target or actual performance. Because actual payouts for 2015 performance were above the target level for all of the named executive officers, the amount that would have been payable to the named executive officers was the actual amount paid as reported in the CD&A and the Summary Compensation Table .

Stock Options and Performance Shares (Equity Awards)
Equity Awards would be treated as described in the Termination and Change-in-Control charts above. If Southern Company consummates a merger and is not the surviving company, all Equity Awards vest. However, there is no payment associated with Equity Awards in that situation unless the participants' Equity Awards cannot be converted into surviving company awards. In that event, the value of outstanding Equity Awards would be paid to the named executive officers. In addition, if there is an Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason, Equity Awards vest.

For stock options, the value is the excess of the exercise price and the closing price of Common Stock on December 31, 2015. The value of performance shares is calculated using the closing price of Common Stock on December 31, 2015.

The chart below shows the number of stock options for which vesting would be accelerated under a Southern Company Termination and the amount that would be payable under a Southern Company Termination if there were no conversion to the surviving company's stock options. It also shows the number and value of performance shares that would be paid.

	Number of Equity Awards with Accelerated Vesting (#)		Total Number of Equity Awards Following Accelerated Vesting (#)		Total Payable in Cash without Conversion of Equity Awards ($)
Name	Stock Options	Performance Shares	Stock Options	Performance Shares	
S. W. Connally, Jr.	85,055	20,628	207,580	20,628	2,068,175
X. Liu	21,600	5,772	58,464	5,772	560,841
R. S. Teel	25,183	5,925	109,634	5,925	1,066,993
J. R. Fletcher	13,970	4,568	39,295	4,568	380,910
W. E. Smith	7,680	2,571	19,562	2,571	195,557
B. C. Terry	27,024	6,358	88,132	6,358	727,167

DCP and SBP
The aggregate balances reported in the Nonqualified Deferred Compensation table would be payable to the named executive officers as described in the Traditional Termination and Change-in-Control-Related Events charts above. There is no enhancement or acceleration of payments under these plans associated with termination or change-in-control events, other than the lump-sum payment opportunity described in the above charts. The lump sums that would be payable are those that are reported in the Nonqualified Deferred Compensation table .

Healthcare Benefits
Mr. Smith is retirement-eligible. Healthcare benefits are provided to retirees, and there is no incremental payment associated with the termination or change-in-control events. Because the other named executive officers were not retirement-eligible at the end of 2015, healthcare benefits would not become available until each reaches age 50, except in the case of a change-in-control-related termination, as described in the Change-in-Control-Related Events chart. The estimated cost of providing healthcare insurance premiums for up to a maximum of two years for Mses. Liu and Terry and Messrs. Fletcher and Teel is $17,482, $10,613, $27,597, and $27,597, respectively. The estimated cost of providing healthcare insurance premiums for up to a maximum of three years for Mr. Connally is $42,966 .

Financial Planning Perquisite
An additional year of the financial planning perquisite, which is set at a maximum of $8,700 per year, will be provided after retirement for retirement-eligible named executive officers.

There are no other perquisites provided to the named executive officers under any of the traditional termination or change-in-control-related events .

Severance Benefits
The named executive officers are participants in a change-in-control severance plan. The plan provides severance benefits, including outplacement services, if within two years of a change in control, they are involuntarily terminated, not for cause, or they voluntarily terminate for Good Reason. The severance benefits are not paid unless the named executive officer releases the employing company from any claims he or she may have against the employing company.

The estimated cost of providing the six months of outplacement services is $6,000 per named executive officer. The severance payment is two times the base salary and target payout under the annual Performance Pay Program for Mr. Connally and one times the base salary and target payout under the annual Performance Pay Program for the other named executive officers. If any portion of the severance amount constitutes an "excess parachute payment" under Section 280G of the Internal Revenue Code and is therefore subject to an excise tax, the severance amount will be reduced unless the after-tax "unreduced amount" exceeds the after-tax "reduced amount." Excise tax gross-ups will not be provided on change-in-control severance payments.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2015 in connection with a change in control.

Name	**Severance Amount ($)**
S. W. Connally, Jr.	1,363,581
X. Liu	396,736
R. S. Teel	397,629
J. R. Fletcher	348,681
W. E. Smith	286,378
B. C. Terry	406,382

DIRECTOR COMPENSATION

Only non-employee directors of Gulf Power are compensated for service on the board of directors.

During 2015, the pay components for non-employee directors were:

Annual cash retainer:	$22,000 per year
Annual stock retainer:	$19,500 per year in Common Stock
Board meeting fees:	If more than five meetings are held in a calendar year, $1,200 will be paid for participation beginning with the sixth meeting.
Committee meeting fees:	If more than five meetings of any one committee are held in a calendar year, $1,000 will be paid for participation in each meeting of that committee beginning with the sixth meeting.

DIRECTOR DEFERRED COMPENSATION PLAN

Any deferred quarterly equity grants or stock retainers are required to be deferred in the Deferred Compensation Plan For Directors of Gulf Power Company (Director Deferred Compensation Plan) and are invested in Common Stock units which earn dividends as if invested in Common Stock. Earnings are reinvested in additional stock units. Upon leaving the board, distributions are made in shares of Common Stock or cash.

In addition, directors may elect to defer up to 100% of their remaining compensation in the Director Deferred Compensation Plan until membership on the board ends. Deferred compensation may be invested as follows, at the director's election:

- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in shares of Common Stock or cash upon leaving the board;
- at prime interest which is paid in cash upon leaving the board.

All investments and earnings in the Director Deferred Compensation Plan are fully vested and, at the election of the director, may be distributed in a lump sum payment or in up to 10 annual distributions after leaving the board **.**

DIRECTOR COMPENSATION TABLE

The following table reports all compensation to Gulf Power's non-employee directors during 2015, including amounts deferred in the Director Deferred Compensation Plan. Non-employee directors do not receive Non-Equity Incentive Plan Compensation or stock option awards, and there is no pension plan for non-employee directors **.**

Name	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (3)	Total ($)
Allan G. Bense	22,000	19,500	0	415	41,915
Deborah H. Calder	22,000	19,500	0	342	41,842
William C. Cramer, Jr.	22,000	19,500	0	379	41,879
Julian B. MacQueen	22,000	19,500	0	391	41,891
J. Mort O'Sullivan III	22,000	19,500	0	391	41,891
Michael T. Rehwinkel	22,000	19,500	0	391	41,891
Winston E. Scott	22,000	19,500	0	391	41,891

(1) Includes amounts voluntarily deferred in the Director Deferred Compensation Plan.

(2) Includes fair market value of equity grants on grant dates. All such stock awards are vested immediately upon grant.

(3) Consists of reimbursement for taxes on imputed income associated with gifts and activities provided to attendees at Southern Company system-sponsored events.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Compensation Committee is made up of non-employee directors of Southern Company who have never served as executive officers of Southern Company or Gulf Power. During 2015, none of Southern Company's or Gulf Power's executive officers served on the board of directors of any entities whose directors or executive officers serve on the Compensation Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership (Applicable to Gulf Power only).

Security Ownership of Certain Beneficial Owners . Southern Company is the beneficial owner of 100% of the outstanding common stock of Gulf Power. The number of outstanding shares reported in the table below is as of January 31, 2016.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	The Southern Company 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308		100%
	Registrant: Gulf Power	5,642,717	

Security Ownership of Management. The following tables show the number of shares of Common Stock owned by the directors, nominees, and executive officers as of December 31, 2015. It is based on information furnished by the directors, nominees, and executive officers. The shares beneficially owned by all directors, nominees, and executive officers as a group constitute less than one percent of the total number of shares of Common Stock outstanding on December 31, 2015.

		Shares Beneficially Owned Include:		
Name of Directors, Nominees, and Executive Officers	**Shares Beneficially Owned (1)**	**Deferred Stock Units (2)**	**Shares Individuals Have Rights to Acquire Within 60 Days (3)**	**Shares Held By Family Member (4)**
S. W. Connally, Jr.	188,536	0	176,204	0
Allan G. Bense	4,457	0	0	0
Deborah H. Calder	2,627	2,098	0	0
William C. Cramer, Jr.	19,293	18,278	0	0
Julian B. MacQueen	1,453	0	0	0
J. Mort O'Sullivan III	3,877	3,877	0	0
Michael T. Rehwinkel	946	0	0	0
Winston E. Scott	6,115	0	0	0
Jim R. Fletcher	37,280	0	34,174	0
Xia Liu	52,157	0	49,667	0
Wendell E. Smith	21,816	0	16,724	0
Richard S. Teel	102,122	0	100,416	2,973
Bentina C. Terry	86,854	0	78,240	0
Directors, Nominees, and Executive Officers as a group (14 people)	632,110	24,253	499,101	2,973

(1) "Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security and/or investment power with respect to a security or any combination thereof.

(2) Indicates the number of deferred stock units held under the Director Deferred Compensation Plan.

(3) Indicates shares of Common Stock that certain executive officers have the right to acquire within 60 days. Shares indicated are included in the Shares Beneficially Owned column.

(4) Shares indicated are included in the Shares Beneficially Owned column.

Changes in Control. Southern Company and Gulf Power know of no arrangements which may at a subsequent date result in any change in control.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Transactions with Related Persons.

In 2015, Mr. Antonio Terry, the spouse of Ms. Bentina Terry, an executive officer of Gulf Power, was employed by Gulf Power as a Senior Engineer and received compensation of $120,670.

Review, Approval or Ratification of Transactions with Related Persons.

Gulf Power does not have a written policy pertaining solely to the approval or ratification of "related party transactions." Southern Company has a Code of Ethics as well as a Contract Guidance Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for most transactions above $10,000 or approval based on documented business needs for sole sourcing arrangements. The approval and ratification of any related party transactions would be subject to these written policies and procedures which include a determination of the need for the goods and services; preparation and evaluation of requests for proposals by supply chain management; the writing of contracts; controls and guidance regarding the evaluation of the proposals; and negotiation of contract terms and conditions. As appropriate, these contracts are also reviewed by individuals in the legal, accounting, and/or risk management/services departments prior to being approved by the responsible individual. The responsible individual will vary depending on the department requiring the goods and services, the dollar amount of the contract, and the appropriate individual within that department who has the authority to approve a contract of the applicable dollar amount.

Director Independence.

The board of directors of Gulf Power consists of seven non-employee directors (Ms. Deborah H. Calder and Messrs. Allan G. Bense, William C. Cramer, Jr., Julian B. MacQueen, J. Mort O'Sullivan, III, Michael T. Rehwinkel, and Winston E. Scott) and Mr. Connally.

Southern Company owns all of Gulf Power's outstanding common stock. Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance. Gulf Power has voluntarily complied with certain NYSE listing standards relating to corporate governance where such compliance was deemed to be in the best interests of Gulf Power's shareholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents the fees billed to Gulf Power and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2015 and 2014:

	2015	2014
	(in thousands)	
Gulf Power		
Audit Fees (1)	$ 1,359	$ 1,427
Audit-Related Fees	2	—
Tax Fees	—	—
All Other Fees (2)	1	12
Total	$ 1,362	$ 1,439
Southern Power		
Audit Fees (1)	$ 1,478	$ 1,143
Audit-Related Fees	3	—
Tax Fees	—	—
All Other Fees (3)	5	2
Total	$ 1,486	$ 1,145

(1) Includes services performed in connection with financing transactions.
(2) Represents registration fees for attendance at Deloitte & Touche-sponsored education seminars in 2014 and 2015, subscription fees for Deloitte & Touche's technical accounting research tool in 2014 and 2015, and information technology consulting services related to general ledger software of Gulf Power in 2014.
(3) Represents registration fees for attendance at Deloitte & Touche-sponsored education seminars in 2014 and 2015, subscription fees for Deloitte & Touche's technical accounting research tool in 2014 and 2015, and information technology consulting services related to general ledger software of Southern Power in 2014.

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided by Deloitte & Touche LLP in fiscal years 2015 and 2014 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

PART IV

Item 15. **EXHIBITS AND FINANCIAL STATEMENT SCHEDULES**

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Financial Statements and Financial Statement Schedules:

Management's Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Alabama Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Georgia Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Gulf Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Mississippi Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Power and Subsidiary Companies is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statements and financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, as well as the Report of Independent Registered Public Accounting Firm on the financial statements of Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power are listed in the Index to the Financial Statement Schedules at page S-1.

(2) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power are listed in the Exhibit Index at page E-1.

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By: Thomas A. Fanning
Chairman, President, and
Chief Executive Officer

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

Date: February 26, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

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

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

Ann P. Daiss
Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Juanita Powell Baranco	*Donald M. James*
Jon A. Boscia	*John D. Johns*
Henry A. Clark III	*Dale E. Klein*
David J. Grain	*William G. Smith, Jr.*
Veronica M. Hagen	*Steven R. Specker*
Warren A. Hood, Jr.	*Larry D. Thompson*
Linda P. Hudson	*E. Jenner Wood III*

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

Date: February 26, 2016

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By: Mark A. Crosswhite
Chairman, President, and Chief Executive Officer

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

Date: February 26, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Mark A. Crosswhite
Chairman, President, Chief Executive Officer, and Director
(Principal Executive Officer)

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

Anita Allcorn-Walker
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong
Ralph D. Cook
David J. Cooper, Sr.
Grayson Hall
Anthony A. Joseph
Patricia M. King
James K. Lowder
Malcolm Portera
Robert D. Powers
Catherine J. Randall
C. Dowd Ritter
James H. Sanford
R. Mitchell Shackleford, III

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

Date: February 26, 2016

GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By: W. Paul Bowers
Chairman, President, and Chief Executive Officer

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

Date: February 26, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

W. Paul Bowers
Chairman, President, Chief Executive Officer, and Director
(Principal Executive Officer)

W. Ron Hinson
Executive Vice President, Chief Financial Officer,
Treasurer, and Corporate Secretary
(Principal Financial Officer)

David P. Poroch
Comptroller and Vice President
(Principal Accounting Officer)

Directors:

Robert L. Brown, Jr.
Anna R. Cablik
Stephen S. Green
Kessel D. Stelling, Jr.
Jimmy C. Tallent
Charles K. Tarbutton
Beverly Daniel Tatum
D. Gary Thompson
Clyde C. Tuggle
Richard W. Ussery

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

Date: February 26, 2016

GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By: *S. W. Connally, Jr.*
Chairman, President, and Chief Executive Officer

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

Date: *February 26, 2016*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

S. W. Connally, Jr.
Chairman, President, Chief Executive Officer, and Director
(Principal Executive Officer)

Xia Liu
Vice President and Chief Financial Officer
(Principal Financial Officer)

Janet J. Hodnett
Comptroller
(Principal Accounting Officer)

Directors:

Allan G. Bense	*J. Mort O'Sullivan, III*
Deborah H. Calder	*Michael T. Rehwinkel*
William C. Cramer, Jr.	*Winston E. Scott*
Julian B. MacQueen	

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

Date: February 26, 2016

MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By: *Anthony L. Wilson*
President and Chief Executive Officer

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

Date: *February 26, 2016*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Anthony L. Wilson
President, Chief Executive Officer, and Director
(Principal Executive Officer)

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

Cynthia F. Shaw
Comptroller
(Principal Accounting Officer)

Directors:

Carl J. Chaney	*Mark E. Keenum*
L. Royce Cumbest	*Christine L. Pickering*
Thomas A. Dews	*Phillip J. Terrell*
G. Edison Holland, Jr.	*M. L. Waters*

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

Date: February 26, 2016

SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN POWER COMPANY

By: *Oscar C. Harper IV*
President and Chief Executive Officer

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

Date: *February 26, 2016*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

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

William C. Grantham
Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Elliott L. Spencer
Comptroller and Corporate Secretary
(Principal Accounting Officer)

Directors:

Art P. Beattie
Thomas A. Fanning
Kimberly S. Greene
James Y. Kerr II
Mark S. Lantrip
Joseph A. Miller
Christopher C. Womack

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

Date: February 26, 2016

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:

No annual report, proxy statement, form of proxy or other proxy soliciting material has been sent to security holders of the registrant during the period covered by this Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Southern Company

We have audited the consolidated financial statements of Southern Company and Subsidiaries (the Company) as of December 31, 2015 and 2014 , and for each of the three years in the period ended December 31, 2015 , and the Company's internal control over financial reporting as of December 31, 2015 , and have issued our report thereon dated February 26, 2016 ; such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company (page S-2) listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP
Atlanta, Georgia
February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Alabama Power Company

We have audited the financial statements of Alabama Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2015 and 2014 , and for each of the three years in the period ended December 31, 2015 , and have issued our report thereon dated February 26, 2016 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-3) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP

Birmingham, Alabama
February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the financial statements of Georgia Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2015 and 2014 , and for each of the three years in the period ended December 31, 2015 , and have issued our report thereon dated February 26, 2016 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-4) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the financial statements of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2015 and 2014 , and for each of the three years in the period ended December 31, 2015 , and have issued our report thereon dated February 26, 2016 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-5) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Mississippi Power Company

We have audited the financial statements of Mississippi Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2015 and 2014 , and for each of the three years in the period ended December 31, 2015 , and have issued our report thereon dated February 26, 2016 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-6) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2016

INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedules I through V not listed above are omitted as not applicable or not required. A Schedule II for Southern Power Company and Subsidiary Companies is not being provided because there were no reportable items for the three-year period ended December 31, 2015 . Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2015 , 2014 , AND 2013
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2015	$ 18,253	$ 31,074	$ —	$ 35,986	$ 13,341
2014	17,855	43,537	—	43,139	18,253
2013	16,984	36,788	—	35,917	17,855

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2015 , 2014 , AND 2013
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions (Note)	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Provision for uncollectible accounts					
2015	$ 9,143	$ 13,500	$ —	$ 13,046	$ 9,597
2014	8,350	14,309	—	13,516	9,143
2013	8,450	12,327	—	12,427	8,350

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2015 , 2014 , AND 2013
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2015	$ 6,076	$ 16,862	$ —	$ 20,791	$ 2,147
2014	5,074	24,141	—	23,139	6,076
2013	6,259	18,362	—	19,547	5,074

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GULF POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2015 , 2014 , AND 2013
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions (Note)	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Provision for uncollectible accounts					
2015	$ 2,087	$ 2,041	$ —	$ 3,353	$ 775
2014	1,131	4,304	—	3,348	2,087
2013	1,490	1,900	—	2,259	1,131

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2015 , 2014 , AND 2013
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2015	$ 825	$ (1,994)	$ —	$ (1,456)	$ 287
2014	3,018	562	—	2,755	825
2013	373	3,757	—	1,112	3,018

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

The refund ordered by the Mississippi PSC pursuant to the 2015 Mississippi Supreme Court decision relative to Mirror CWIP involved refunding all billed amounts to all historical customers and included an interest component. The refund of approximately $371 million was of sufficient magnitude to resolve most past due amounts beyond 30 days aged receivables, accounting for the negative provision of $(1,994) , where risk of collectibility was offset by applying the refund to past due amounts. It was also of sufficient size to offset amounts previously written off in the 2012-2015 time frame, accounting for the net recoveries of $(1,456) .

For more information regarding the 2015 decision of the Mississippi Supreme Court related to the Mirror CWIP refund in fourth quarter 2015, see Note 3 to the financial statement of Mississippi Power under "Integrated Coal Gasification Combined Cycle – 2013 MPSC Rate Order" in Item 8 herein.

EXHIBIT INDEX

The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

(2) Plan of acquisition, reorganization, arrangement, liquidation or succession

Southern Company

(a) 1 — Agreement and Plan of Merger by and among Southern Company, Merger Sub, and AGL Resources, dated August 23, 2015. (Designated in Form 8-K dated August 23, 2015, File No. 1-3526, as Exhibit 2.1.)

(3) Articles of Incorporation and By-Laws

Southern Company

(a) 1 — Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through May 27, 2010. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A, in Certificate of Notification, File No. 70-8181, as Exhibit A, and in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.1.)

(a) 2 — By-laws of Southern Company as amended effective May 27, 2015, and as presently in effect. (Designated in Form 8-K dated May 27, 2015, File No. 1-3526, as Exhibit 3.1.)

Alabama Power

(b) 1 — Charter of Alabama Power and amendments thereto through April 25, 2008. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Alabama Power's Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Alabama Power's Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1, in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b)(1), in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 12, 2007, File No. 1-3164, as Exhibit 4.5, in Form 8-K dated October 17, 2007, File No. 1-3164, as Exhibit 4.5, and in Alabama Power's Form 10-Q for the quarter ended March 31, 2008, File No. 1-3164, as Exhibit 3(b)1.)

(b) 2 — Amended and Restated By-laws of Alabama Power effective February 10, 2014, and as presently in effect. (Designated in Form 8-K dated February 10, 2014, File No 1-3164, as Exhibit 3.1.)

Georgia Power

(c) 1 — Charter of Georgia Power and amendments thereto through October 9, 2007. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Georgia Power's Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Georgia Power's Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Georgia Power's Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2, in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1, and in Form 8-K dated October 3, 2007, File No. 1-6468, as Exhibit 4.5.)

(c) 2 — By-laws of Georgia Power as amended effective May 20, 2009, and as presently in effect. (Designated in Form 8-K dated May 20, 2009, File No. 1-6468, as Exhibit 3(c)2.)

Gulf Power

(d)	1	—	Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through June 17, 2013. (Designated in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 3.1, in Form 8-K dated November 9, 2005, File No. 001-31737, as Exhibit 4.7, in Form 8-K dated October 16, 2007, File No. 001-31737, as Exhibit 4.5, and in Form 8-K dated June 10, 2013, File No. 001-31737, as Exhibit 4.7.)
(d)	2	—	By-laws of Gulf Power as amended effective November 2, 2005, and as presently in effect. (Designated in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 3.2.)

Mississippi Power

(e)	1	—	Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 001-11229, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Mississippi Power's Form 10-K for the year ended December 31, 1997, File No. 001-11229, as Exhibit 3(e)2, in Mississippi Power's Form 10-K for the year ended December 31, 2000, File No. 001-11229, as Exhibit 3(e)2, and in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.6.)
(e)	2	—	By-laws of Mississippi Power as amended effective October 19, 2015, and as presently in effect. (Designated in Form 8-K dated October 19, 2015, File No. 001-11229, as Exhibit 3.1)

Southern Power

(f)	1	—	Certificate of Incorporation of Southern Power Company dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)
(f)	2	—	By-laws of Southern Power Company effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.)

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

With respect to each of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company, such registrant has not included any instrument with respect to long-term debt that does not exceed 10% of the total assets of such registrant and its subsidiaries. Each such registrant agrees, upon request of the SEC, to furnish copies of any or all such instruments to the SEC.

Southern Company

(a)	1	—	Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through June 12, 2015. (Designated in Form 8-K dated January 11, 2007, File No. 1-3526, as Exhibits 4.1 and 4.2, in Form 8-K dated March 20, 2007, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 13, 2008, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated May 11, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated October 19, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated September 13, 2010, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 16, 2011, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 21, 2013, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 19, 2014, File No. 1-3526, as Exhibits 4.2(a) and 4.2(b), and in Form 8-K dated June 9, 2015, File No. 1-3526, as Exhibit 4.2.)
(a)	2	—	Subordinated Note Indenture dated as of October 1, 2015, between The Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through October 8, 2015. (Designated in Form 8-K dated October 1, 2015, File No. 1-3526, as Exhibits 4.3 and 4.4.)

Alabama Power

(b)	1	—	Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and Regions Bank, as Successor Trustee, and indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 18, 1999, File No. 1-3164, as Exhibit 4.2, and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibits 4.9-A and 4.9-B.)

(b)	2	—	Senior Note Indenture dated as of December 1, 1997, between Alabama Power and Regions Bank, as Successor Trustee, and indentures supplemental thereto through January 13, 2016. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 20, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 17, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 11, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 8, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 16, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 7, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 28, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 12, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 19, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 13, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 21, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 11, 2000, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 22, 2001, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated June 21, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated October 16, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated November 20, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 15, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 10, 2004, File No. 1-3164, as Exhibit 4.2 in Form 8-K dated April 7, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 19, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 9, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 8, 2005, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 11, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 13, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 1, 2006, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 9, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated June 7, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 30, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 11, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 8, 2008, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated February 26, 2009, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated September 27, 2010, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 3, 2011, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 18, 2011, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated January 10, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 9, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 27, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 3, 2013, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 20, 2014, File No. 1-3164, as Exhibit 4.6, in Form 8-K dated March 5, 2015, File No. 1-3164, as Exhibit 4.6, in Form 8-K dated April 9, 2015, File No. 1-3164, as Exhibit 4.6(b), and in Form 8-K dated January 8, 2016, File No. 1-3164, as Exhibit 4.6.)
(b)	3	—	Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)
(b)	4	—	Guarantee Agreement relating to Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)

Georgia Power

(c)	1	—	Senior Note Indenture dated as of January 1, 1998, between Georgia Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through December 4, 2015. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 and 4.2, in Forms 8-K each dated November 19, 1998, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 3, 1999, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated February 15, 2000, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated January 26, 2001, File No. 1-6469 as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 16, 2001, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated May 1, 2001, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 27, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 15, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 13, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 21, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibits 4.1, 4.2 and 4.3, in Form 8-K dated September 8, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated September 23, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated January 12, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated February 12, 2004, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated August 11, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated January 13, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated April 12, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated November 30, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated December 8, 2006, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 6, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 4, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 18, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated July 10, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 24, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 29, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 5, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 12, 2008, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 4, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated December 8, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 9, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 24, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 26, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated September 20, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated January 13, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 12, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 29, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 8, 2012, File No. 1-6468, as Exhibit 4.2(b), in Form 8-K dated August 7, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 8, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2013, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated August 12, 2013, File No. 1-6468, as Exhibit 4.2, and in Form 8-K dated December 1, 2015, File No. 1-6468, as Exhibit 4.2.)
(c)	2	—	Loan Guarantee Agreement between Georgia Power and the DOE dated as of February 20, 2014 and Amendment No. 1 thereto dated as of June 4, 2015. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.1 and in Georgia Power's Form 10-Q for the quarter ended June 30, 2015, File No. 1-6468, as Exhibit 10(c)1.)
(c)	3	—	Note Purchase Agreement among Georgia Power, the DOE, and the Federal Financing Bank dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.2.)
(c)	4	—	Future Advance Promissory Note dated February 20, 2014 made by Georgia Power to the FFB. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.3.)
(c)	5	—	Deed to Secure Debt, Security Agreement and Fixture Filing between Georgia Power and PNC Bank, National Association, doing business as Midland Loan Services Inc., a division of PNC Bank, National Association dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.4.)
(c)	6	—	Owners Consent to Assignment and Direct Agreement and Amendment to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement by and among Georgia Power, OPC, MEAG Power, and Dalton dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.5.)

Gulf Power				
	(d)	1	—	Senior Note Indenture dated as of January 1, 1998, between Gulf Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through September 23, 2014. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated August 17, 1999, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 31, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated October 5, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated January 18, 2002, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated March 21, 2003, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 10, 2003, File No. 001-31737, as Exhibits 4.1 and 4.2, in Form 8-K dated September 5, 2003, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated April 6, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated September 13, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated August 11, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated November 28, 2006, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 5, 2007, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 22, 2009, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated April 6, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated September 9, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated May 12, 2011, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated May 15, 2012, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 10, 2013, File No. 001-31737, as Exhibit 4.2, and in Form 8-K dated September 16, 2014, File No. 001-31737, as Exhibit 4.2.)
Mississippi Power				
	(e)	1	—	Senior Note Indenture dated as of May 1, 1998, between Mississippi Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through March 9, 2012. (Designated in Form 8-K dated May 14, 1998, File No. 001-11229, as Exhibits 4.1, 4.2(a) and 4.2(b), in Form 8-K dated March 22, 2000, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 12, 2002, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated April 24, 2003, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated June 24, 2005, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 8, 2007, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2009, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated October 11, 2011, File No. 001-11229, as Exhibits 4.2(a) and 4.2(b), and in Form 8-K dated March 5, 2012, File No. 001-11229, as Exhibit 4.2(b).)
Southern Power				
	(f)	1	—	Senior Note Indenture dated as of June 1, 2002, between Southern Power Company and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through November 17, 2015. (Designated in Registration No. 333-98553 as Exhibits 4.1 and 4.2 and in Southern Power Company's Form 10-Q for the quarter ended June 30, 2003, File No. 333-98553, as Exhibit 4(g)1, in Form 8-K dated November 13, 2006, File No. 333-98553, as Exhibit 4.2, in Form 8-K dated September 14, 2011, File No. 333-98553, as Exhibit 4.4, in Form 8-K dated July 10, 2013, File No. 333-98553, as Exhibit 4.4, in Form 8-K dated May 14, 2015, File No. 333-98553, as Exhibits 4.4(a) and 4.4(b), and in Form 8-K dated November 12, 2015, File No. 333-98553, as Exhibits 4.4(a) and 4.4(b).)

(10) Material Contracts

Southern Company

#	(a)	1	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. (Designated in Southern Company's Form 8-K dated May 25, 2011, File No. 1-3526, as Exhibit 10.1.)
#	(a)	2	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Southern Company's Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)3.)
#	(a)	3	—	Deferred Compensation Plan for Outside Directors of The Southern Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective April 1, 2015. (Designated in Southern Company's Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)3 and in Southern Company's Form 10-Q for the quarter ended June 30, 2015, File No. 1-3526, as Exhibit 10(a)1.)
#	(a)	4	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)4 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)5.)

#	(a)	5	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)6 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)(8).)
#	(a)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)7 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)10.)
#	(a)	7	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1.)
#	(a)	8	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	9	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)18.)
#	(a)	10	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)20.)
#	(a)	11	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)23, in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)22, and in Southern Company's Form 10-K for the year ended December 31, 2010, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	12	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)24 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)24.)
#	(a)	13	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. (Designated in Form 10-K for the year ended December 31, 2014, File No. 1-3526, as Exhibit 10(a)17).
#	(a)	14	—	Retention and Restricted Stock Unit Award Agreement between Southern Nuclear and Stephen E. Kuczynski effective as of July 11, 2011. (Designated in Form 10-Q for the quarter ended March 31, 2013, File No. 1-3526, as Exhibit 10(a)3.)
#	(a)	15	—	Retention Award Agreement between Southern Nuclear and Stephen E. Kuczynski effective as of October 20, 2014. (Designated in Form 10-Q for the quarter ended March 31, 2015, File No. 1-3526, as Exhibit 10(a)1.)
#	(a)	16	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. (Designated in Definitive Proxy Statement filed April 10, 2015, File No. 1-3526, as Appendix A.)
	(a)	17	—	Commitment Letter dated August 23, 2015. (Designated in Form 8-K dated August 23, 2015, File No. 1-3526, as Exhibit 10.1.)

	(a)	18	—	Bridge Credit Agreement dated as of September 30, 2015, among Southern Company, as the Borrower, the Lenders identified therein, and Citibank, N.A., as Administrative Agent. (Designated in Form 8-K dated September 30, 2015, File No. 1-3526, as Exhibit 10.1.)
# *	(a)	19	—	Second Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 2, 2016.
# *	(a)	20	—	Second Amendment to The Southern Company Supplemental Benefit Plan effective January 2, 2016.
# *	(a)	21	—	Second Amendment to The Southern Company Deferred Compensation Plan effective October 29, 2014.
Alabama Power				
	(b)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. (Designated in Form 10-Q for the quarter ended March 31, 2007, File No. 1-3164, as Exhibit 10(b)5.)
#	(b)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(b)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(b)	4	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(b)	5	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(b)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(b)	7	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)12 herein.
#	(b)	8	—	Deferred Compensation Plan for Outside Directors of Alabama Power Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective June 1, 2015. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1 and in Alabama Power's Form 10-Q for the quarter ended June 30, 2015, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	9	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. See Exhibit 10(a)7 herein.
#	(b)	10	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)8 herein.
#	(b)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)9 herein.
#	(b)	12	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(b)	13	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. See Exhibit 10(a)11 herein.
#	(b)	14	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)13 herein.

#	(b)	15	—	Deferred Compensation Agreement between Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS and Philip C. Raymond dated September 15, 2010. (Designated in Alabama Power's Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b)2.)
#	(b)	16	—	Retention Award Agreement between Alabama Power and Steven R. Spencer effective July 15, 2013. (Designated in Form 10-Q for the quarter ended September 30, 2013, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	17	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. See Exhibit 10(a)16 herein.
#	(b)	18	—	Second Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 2, 2016. See Exhibit 10(a)19 herein.
#	(b)	19	—	Second Amendment to The Southern Company Supplemental Benefit Plan effective January 2, 2016. See Exhibit 10(a)20 herein.
#	(b)	20	—	Second Amendment to The Southern Company Deferred Compensation Plan effective October 29, 2014. See Exhibit 10(a)21 herein.
# *	(b)	21	—	Employment Agreement between Alabama Power and Steven R. Spencer effective April 1, 2016.
Georgia Power				
	(c)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
	(c)	2	—	Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)
	(c)	3	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)
	(c)	4	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG Power dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)
#	(c)	5	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(c)	6	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(c)	7	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(c)	8	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(c)	9	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(c)	10	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)12 herein.
#	(c)	11	—	Deferred Compensation Plan For Outside Directors of Georgia Power Company, Amended and Restated Effective January 1, 2008 and First Amendment thereto effective April 1, 2015. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-6468, as Exhibit 10(c)12 and in Form 10-Q for the quarter ended March 31, 2015, File No. 1-6468, as Exhibit 10(c)2.)
#	(c)	12	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. See Exhibit 10(a)7 herein.

#	(c)	13	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)8 herein.
#	(c)	14	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)9 herein.
#	(c)	15	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(c)	16	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. See Exhibit 10(a)11 herein.
	(c)	17	—	Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for OPC, MEAG Power, and Dalton, as owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site, Amendment No. 1 thereto dated as of December 11, 2009, Amendment No. 2 thereto dated as of January 15, 2010, Amendment No. 3 thereto dated as of February 23, 2010, Amendment No. 4 thereto dated as of May 2, 2011, Amendment No. 5 thereto dated as of February 7, 2012, and Amendment No. 6 thereto dated as of January 23, 2014. (Georgia Power requested confidential treatment for certain portions of these documents pursuant to applications for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filings and filed them separately with the SEC.) (Designated in Form 10-Q/A for the quarter ended June 30, 2008, File No. 1-6468, as Exhibit 10(c)1, in Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)29, in Georgia Power's Form 10-Q for the quarter ended March 31, 2010, File No. 1-6468, as Exhibits 10(c)1 and 10(c)2, in Georgia Power's Form 10-Q for the quarter ended June 30, 2011, File No. 1-6468, as Exhibit 10(c)2, in Georgia Power's Form 10-Q for the quarter ended March 31, 2012, File No. 1-6468, as Exhibit 10(c)2, and in Georgia Power's Form 10-Q for the quarter ended March 31, 2014, File No. 1-6468, as Exhibit 10(c)2.)
#	(c)	18	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)13 herein.
#	(c)	19	—	Retention Award Agreement and Amendment thereto between Southern Nuclear and Joseph A. Miller effective January 1, 2013. (Designated in Form 10-K for the year ended December 31, 2012, File No. 1-6468, as Exhibits 10(c)24 and 10(c)25.)
#	(c)	20	—	Deferred Compansation Agreement between Southern Company, Southern Company Services, Inc., and John L. Pemberton, effective October 10, 2008. (Designated in Form 10-Q for the quarter ended March 31, 2015, File No. 1-6468, as Exhibit 10(c)3.)
#	(c)	21	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. See Exhibit 10(a)16 herein.
#	(c)	22	—	Second Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 2, 2016. See Exhibit 10(a)19 herein.
#	(c)	23	—	Second Amendment to The Southern Company Supplemental Benefit Plan effective January 2, 2016. See Exhibit 10(a)20 herein.
#	(c)	24	—	Second Amendment to The Southern Company Deferred Compensation Plan effective October 29, 2014. See Exhibit 10(a)21 herein.
*	(c)	25	—	Amendment No. 7 dated as of January 8, 2016, to Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse Electric Company LLC and CB&I Stone & Webster, Inc., as contractor, for Units 3&4 at the Vogtle Electric Generating Plant Site. (Georgia Power has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filing and filed them separately with the SEC.)

Gulf Power

	(d)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
#	(d)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(d)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(d)	4	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(d)	5	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(d)	6	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)12 herein.
#	(d)	7	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(d)	8	—	Deferred Compensation Plan For Outside Directors of Gulf Power Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective April 1, 2015. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2008, File No. 0-2429, as Exhibit 10(d)1 and in Gulf Power's Form 10-Q for the quarter ended June 30, 2015, File No. 001-11229, as Exhibit 10(d)1.)
#	(d)	9	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. See Exhibit 10(a)7 herein.
#	(d)	10	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)8 herein.
#	(d)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)9 herein.
#	(d)	12	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(d)	13	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. See Exhibit 10(a)11 herein.
#	(d)	14	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)13 herein.
#	(d)	15	—	Deferred Compensation Agreement between Southern Company, Georgia Power, Gulf Power, and Southern Nuclear and Bentina C. Terry dated August 1, 2010. (Designated in Gulf Power's Form 10-Q for the quarter ended September 30, 2010, File No. 001-31737, as Exhibit 10(d)2.)
#	(d)	16	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. See Exhibit 10(a)16 herein.
#	(d)	17	—	Second Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 2, 2016. See Exhibit 10(a)19 herein.
#	(d)	18	—	Second Amendment to The Southern Company Supplemental Benefit Plan effective January 2, 2016. See Exhibit 10(a)20 herein.

#	(d)	19	—	Second Amendment to The Southern Company Deferred Compensation Plan effective October 29, 2014. See Exhibit 10(a)21 herein.

Mississippi Power

	(e)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
	(e)	2	—	Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 1981, File No. 001-11229, as Exhibit 10(f), in Mississippi Power's Form 10-K for the year ended December 31, 1982, File No. 001-11229, as Exhibit 10(f)(2), and in Mississippi Power's Form 10-K for the year ended December 31, 1983, File No. 001-11229, as Exhibit 10(f)(3).)
#	(e)	3	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(e)	4	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(e)	5	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(e)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(e)	7	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)12 herein.
#	(e)	8	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(e)	9	—	Deferred Compensation Plan for Outside Directors of Mississippi Power Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective April 1, 2015. (Designated in Mississippi Power's Form 10-Q for the quarter ended March 31, 2008, File No. 001-11229 as Exhibit 10(e)1 and in Mississippi Power's Form 10-Q for the quarter ended June 30, 2015, File No. 001-11229 as Exhibit 10(e)1.)
#	(e)	10	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. See Exhibit 10(a)7 herein.
#	(e)	11	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)8 herein.
#	(e)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)9 herein.
#	(e)	13	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(e)	14	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. See Exhibit 10(a)11 herein.
	(e)	15	—	Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2008, File No. 001-11229, as Exhibit 10(e)22.) (Mississippi Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Mississippi Power omitted such portions from this filing and filed them separately with the SEC.)

#	(e)	16	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)13 herein.
#	(e)	17	—	Amended Deferred Compensation Agreement effective December 31, 2008 between Southern Company, SCS, Georgia Power, Gulf Power and G. Edison Holland, Jr. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 001-11229, as Exhibit 10(a)2.)
#	(e)	18	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. See Exhibit 10(a)16 herein.
#	(e)	19	—	Second Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 2, 2016. See Exhibit 10(a)19 herein.
#	(e)	20	—	Second Amendment to The Southern Company Supplemental Benefit Plan effective January 2, 2016. See Exhibit 10(a)20 herein.
#	(e)	21	—	Second Amendment to The Southern Company Deferred Compensation Plan effective October 29, 2014. See Exhibit 10(a)21 herein.
Southern Power				
	(f)	1	—	Service contract dated as of January 1, 2001, between SCS and Southern Power Company. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)(2).)
	(f)	2	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
	(f)	3	—	Amended and Restated Engineering, Procurement and Construction Agreement between Desert Stateline LLC and First Solar Electric (California), Inc. dated as of August 31, 2015. (Southern Power has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Southern Power omitted such portions from the filing and filed them separately with the SEC.)(Designated in Form 10-Q for the quarter ended September 30, 2015, File No. 333-98533, as Exhibit 10(e)1.)

(14) Code of Ethics

Southern Company			
	(a)	—	The Southern Company Code of Ethics. (Designated in Southern Company's Form 10-K for the year ended December 31, 2013, File No. 1-3526, as Exhibit 14(a).)
Alabama Power			
	(b)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Georgia Power			
	(c)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Gulf Power			
	(d)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Mississippi Power			
	(e)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Southern Power			
	(f)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.

(21) Subsidiaries of Registrants

Southern Company			
*	(a)	—	Subsidiaries of Registrant.
Alabama Power			
	(b)	—	Subsidiaries of Registrant. See Exhibit 21(a) herein.
Georgia Power			
	(c)	—	Subsidiaries of Registrant. See Exhibit 21(a) herein.
Gulf Power			
	(d)	—	Subsidiaries of Registrant. See Exhibit 21(a) herein.

	Mississippi Power			
	(e)		—	Subsidiaries of Registrant. See Exhibit 21(a) herein.
	Southern Power			
	Omitted pursuant to General Instruction I(2)(b) of Form 10-K.			
(23)	**Consents of Experts and Counsel**			
	Southern Company			
*	(a)	1	—	Consent of Deloitte & Touche LLP.
	Alabama Power			
*	(b)	1	—	Consent of Deloitte & Touche LLP.
	Georgia Power			
*	(c)	1	—	Consent of Deloitte & Touche LLP.
	Gulf Power			
*	(d)	1	—	Consent of Deloitte & Touche LLP.
	Southern Power			
*	(f)	1	—	Consent of Deloitte & Touche LLP.
(24)	**Powers of Attorney and Resolutions**			
	Southern Company			
*	(a)		—	Power of Attorney and resolution.
	Alabama Power			
*	(b)		—	Power of Attorney and resolution.
	Georgia Power			
*	(c)		—	Power of Attorney and resolution.
	Gulf Power			
*	(d)		—	Power of Attorney and resolution.
	Mississippi Power			
*	(e)	1	—	Power of Attorney and resolution.
*	(e)	2	—	Power of Attorney for Anthony L. Wilson.
	Southern Power			
*	(f)	1	—	Power of Attorney and resolution.
*	(f)	2	—	Power of Attorney for Joseph A. Miller.
(31)	**Section 302 Certifications**			
	Southern Company			
*	(a)	1	—	Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(a)	2	—	Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
	Alabama Power			
*	(b)	1	—	Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(b)	2	—	Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
	Georgia Power			
*	(c)	1	—	Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(c)	2	—	Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Gulf Power				
*	(d)	1	—	Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(d)	2	—	Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Mississippi Power				
*	(e)	1	—	Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(e)	2	—	Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Southern Power				
*	(f)	1	—	Certificate of Southern Power Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(f)	2	—	Certificate of Southern Power Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company			
*	(a)	—	Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Alabama Power			
*	(b)	—	Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Georgia Power			
*	(c)	—	Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Gulf Power			
*	(d)	—	Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Mississippi Power			
*	(e)	—	Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Southern Power			
*	(f)	—	Certificate of Southern Power Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(101) XBRL-Related Documents

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