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

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.

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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	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.

	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

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

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.

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

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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:
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Pensacola, FL 32520
(850) 444-6111

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

Auditors
Deloitte & Touche LLP
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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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