GEORGIA POWER COMPANY

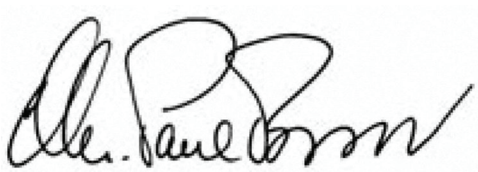
2016 ANNUAL REPORT

Georgia Power

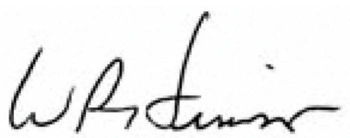
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2016 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2016.



W. Paul Bowers
Chairman, President, and Chief Executive Officer



W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer

February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015, 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, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements (pages 33 to 80) present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 21, 2017

DEFINITIONS

Term	Meaning
2013 ARP	Alternative Rate Plan approved by the Georgia PSC in 2013 for Georgia Power for the years 2014 through 2016 and subsequently extended through 2019
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CWIP	Construction work in progress
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
GAAP	U.S. generally accepted accounting principles
Gulf Power	Gulf Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NCCR	Nuclear Construction Cost Recovery
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
PTC	Production tax credit
ROE	Return on equity
S&P	S&P Global Ratings, a division of S&P Global Inc.
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
Southern Company	The Southern Company

DEFINITIONS
(continued)

Term	Meaning
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern LINC, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional electric operating companies	Alabama Power, Georgia Power Company, Gulf Power, and Mississippi Power

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

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the 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, stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. In addition, construction continues on Plant Vogtle Units 3 and 4. The Company will own a 45.7% interest in these two nuclear generating units to increase its generation diversity and meet future supply needs. The Company has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information on Plant Vogtle Units 3 and 4.

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC on April 14, 2016, the Company's 2013 ARP will continue in effect until December 31, 2019, and the Company will be required to file its next base rate case by July 1, 2019. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate Plans" herein for additional information.

The Company continues to focus on several key performance indicators, including, but not limited to, customer satisfaction, plant availability, system reliability, the execution of major construction projects, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance.

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

Earnings

The Company's 2016 net income after dividends on preferred and preference stock was $1.3 billion, representing a $70 million, or 5.6%, increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1, 2016, as authorized by the Georgia PSC, the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers, and higher retail revenues in the third quarter 2016 due to warmer weather as compared to the corresponding period in 2015, partially offset by an adjustment for an expected refund to retail customers as a result of the Company's retail ROE exceeding the allowed retail ROE range under the 2013 ARP during 2016. Higher non-fuel operating expenses also partially offset the revenue increase.

The Company's 2015 net income after dividends on preferred and preference stock was $1.3 billion, representing a $35 million, or 2.9%, increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1, 2015, as authorized by the Georgia PSC, and lower non-fuel operations and maintenance expenses, partially offset by the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers.

See Note 1 to the financial statements under "General" and FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate Plans" herein for additional information related to the 2015 error correction and the 2016 expected refund to retail customers, respectively.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	**2016**	2015
		(in millions)	
Operating revenues	**$ 8,383**	**$ 57**	$ (662)
Fuel	**1,807**	**(226)**	(514)
Purchased power	**879**	**15**	(124)
Other operations and maintenance	**1,960**	**116**	(58)
Depreciation and amortization	**855**	**9**	—
Taxes other than income taxes	**405**	**14**	(18)
Total operating expenses	**5,906**	**(72)**	(714)
Operating income	**2,477**	**129**	52
Interest expense, net of amounts capitalized	**388**	**25**	15
Other income (expense), net	**38**	**(23)**	38
Income taxes	**780**	**11**	40
Net income	**1,347**	**70**	35
Dividends on preferred and preference stock	**17**	**—**	—
Net income after dividends on preferred and preference stock	**$ 1,330**	**$ 70**	$ 35

Operating Revenues

Operating revenues for 2016 were $8.4 billion, reflecting a $57 million increase from 2015. Details of operating revenues were as follows:

	Amount	
	2016	2015
	(in millions)	
Retail — prior year	**$ 7,727**	$ 8,240
Estimated change resulting from —		
Rates and pricing	**154**	88
Sales growth (decline)	**(10)**	63
Weather	**113**	(19)
Fuel cost recovery	**(212)**	(645)
Retail — current year	**7,772**	7,727
Wholesale revenues —		
Non-affiliates	**175**	215
Affiliates	**42**	20
Total wholesale revenues	**217**	235
Other operating revenues	**394**	364
Total operating revenues	**$ 8,383**	$ 8,326
Percent change	**0.7%**	(7.4)%

Retail base revenues of $5.6 billion in 2016 increased $256 million, or 4.8%, compared to 2015. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to increases in base tariffs approved under the 2013 ARP and the NCCR tariff, all effective January 1, 2016. Also contributing to the increase was the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing. The increase was partially offset by an adjustment for an expected refund to retail customers as a result of the Company's retail ROE exceeding the allowed retail ROE range under the 2013 ARP during 2016. In 2016, residential base revenues increased $152 million, or 6.3%, commercial base revenues increased $65 million, or 3.0%, and industrial base revenues increased $39 million, or 5.6%, compared to 2015.

Retail base revenues of $5.3 billion in 2015 increased $133 million, or 2.6%, compared to 2014. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to increases in base tariffs approved under the 2013 ARP and the NCCR tariff, all effective January 1, 2015, partially offset by the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing. In 2015, residential base revenues increased $104 million, or 4.5%, commercial base revenues increased $70 million, or 3.4%, and industrial base revenues decreased $41 million, or 5.6%, compared to 2014.

See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" and " – Nuclear Construction" for additional information. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses and do not affect net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

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

	2016	2015	2014
		(in millions)	
Capacity and other	**$ 72**	$ 108	$ 164
Energy	**103**	107	171
Total non-affiliated	**$ 175**	$ 215	$ 335

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amounts billable under the contract terms and provide for recovery of fixed costs and a return on investment. Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy.

Wholesale revenues from non-affiliated sales decreased $40 million, or 18.6%, in 2016 as compared to 2015 and decreased $120 million, or 35.8%, in 2015 as compared to 2014. The decrease in 2016 was related to decreases of $36 million in capacity revenues and $4 million in energy revenues. The decrease in 2015 was related to decreases of $64 million in energy revenues and $56 million in capacity revenues. The decreases in capacity revenues reflect the expiration of wholesale contracts in the second quarter 2016 and in December 2014, respectively, as well as the retirement of 14 coal-fired generating units since March 31, 2015 as a result of the Company's environmental compliance strategy. The decreases in energy revenues were primarily due to lower fuel prices. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" herein for additional information regarding the Company's environmental compliance strategy.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost. In 2016, wholesale revenues from sales to affiliates increased $22 million as compared to 2015 due to a 153.5% increase in KWH sales as a result of the lower cost of Company-owned generation compared to the market cost of available energy, partially offset by lower coal and natural gas prices. In 2015, wholesale revenues from sales to affiliates decreased $22 million as compared to 2014 due to lower natural gas prices and a 50.6% decrease in KWH sales due to the higher cost of Company-owned generation compared to the market cost of available energy.

Other operating revenues increased $30 million, or 8.2%, in 2016 from the prior year primarily due to a $14 million increase related to customer temporary facilities services revenues and a $12 million increase in outdoor lighting revenues due to increased sales in new and replacement markets, primarily attributable to conversions from traditional to LED lighting. Other operating revenues decreased $7 million, or 1.9%, in 2015 from the prior year primarily due to a $16 million decrease in transmission service revenues primarily as a result of a contract that expired in December 2014, partially offset by an $11 million increase in outdoor lighting revenues.

Energy Sales

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

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2016	**2016**	2015	**2016**	2015
	(in billions)				
Residential	**27.6**	**3.5%**	(1.8)%	**1.0 %**	1.0%
Commercial	**32.9**	**0.7**	0.9	**(1.0)**	1.5
Industrial	**23.8**	**(0.2)**	1.1	**(0.9)**	1.0
Other	**0.6**	**(3.5)**	(0.2)	**(3.5)**	(0.1)
Total retail	**84.9**	**1.3**	0.1	**(0.4)%**	1.2%
Wholesale					
Non-affiliates	**3.4**	**(2.5)**	(19.0)		
Affiliates	**1.4**	**153.5**	(50.6)		
Total wholesale	**4.8**	**18.8**	(25.5)		
Total energy sales	**89.7**	**2.1%**	(1.5)%		

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.

In 2016, KWH sales for the residential class increased 3.5% compared to 2015 primarily due to warmer weather in the third quarter 2016 as compared to the corresponding period in 2015 and increased customer growth, partially offset by decreased customer usage. Weather-adjusted residential KWH sales increased by 1.0% primarily due to an increase of approximately 28,000 residential customers since December 31, 2015, partially offset by a decline in customer usage primarily resulting from an increase in multi-family housing and efficiency improvements in residential appliances and lighting. Weather-adjusted commercial KWH sales decreased by 1.0% primarily due to a decline in average customer usage resulting from an increase in electronic commerce transactions and energy saving initiatives, partially offset by an increase of approximately 2,600 commercial customers since December 31, 2015. Weather-adjusted industrial sales decreased 0.9% primarily due to decreased demand in the pipeline, primary metals, stone, clay, and glass, and textile sectors, partially offset by increased demand in the non-manufacturing sector.

In 2015, KWH sales for the residential class decreased compared to 2014 primarily due to milder weather in the first and fourth quarters 2015 as compared to the corresponding periods in 2014 and decreased customer usage, partially offset by an increase in customer growth. Weather-adjusted residential KWH sales increased by 1.0% primarily due to an increase of approximately 25,000 residential customers during 2015. Household income, one of the primary drivers of residential customer usage, had modest growth in 2015. Weather-adjusted commercial KWH sales increased by 1.5% primarily due to an increase of approximately 3,000 customers and an increase in customer usage. Weather-adjusted industrial KWH sales increased by 1.0% primarily due to increased demand in the pipeline, rubber, and paper sectors, partially offset by decreased demand in the chemicals and primary metals sectors.

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

Fuel and Purchased Power Expenses

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

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

	2016	2015	2014
Total generation *(in billions of KWHs)*	**68.4**	65.9	69.9
Total purchased power *(in billions of KWHs)*	**24.8**	25.6	23.1
Sources of generation *(percent)* —			
Coal	**36**	34	41
Nuclear	**24**	25	22
Gas	**38**	39	35
Hydro	**2**	2	2
Cost of fuel, generated *(in cents per net KWH)* —			
Coal	**3.28**	4.55	4.52
Nuclear	**0.85**	0.78	0.90
Gas	**2.36**	2.47	3.67
Average cost of fuel, generated *(in cents per net KWH)*	**2.33**	2.77	3.40
Average cost of purchased power *(in cents per net KWH)*(*)	**4.53**	4.33	5.20

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

Fuel and purchased power expenses were $2.7 billion in 2016, a decrease of $211 million, or 7.3%, compared to 2015. The decrease was primarily due to a $334 million decrease in the average cost of fuel due to lower coal and natural gas prices and a $37 million decrease in the volume of KWHs purchased. Partially offsetting these decreases were a $111 million increase in the volume of KWHs generated to meet customer demand and a $49 million increase in the average cost of purchased power.

Fuel and purchased power expenses were $2.9 billion in 2015, a decrease of $638 million, or 18.0%, compared to 2014. The decrease was primarily due to a $544 million decrease in the average cost of fuel and purchased power largely as a result of lower natural gas prices and a $228 million decrease in the volume of KWHs generated by coal, partially offset by a $134 million increase in the volume of KWHs purchased due to lower natural gas prices.

Fuel and purchased power energy transactions do not have a significant impact on earnings since these fuel expenses are generally offset by fuel revenues through the Company's fuel cost recovery mechanism. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Fuel

Fuel expense was $1.8 billion in 2016, a decrease of $226 million, or 11.1%, compared to 2015. The decrease was primarily due to a decrease of 18.6% in the average cost of coal and natural gas per KWH generated, partially offset by an increase of 10.0% in the volume of KWHs generated by coal. Fuel expense was $2.0 billion in 2015, a decrease of $514 million, or 20.2%, compared to 2014. The decrease was primarily due to a decrease of 32.7% in the average cost of natural gas per KWH generated and a decrease of 22.2% in the volume of KWHs generated by coal, partially offset by a 6.2% increase in the volume of KWHs generated by natural gas.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $361 million in 2016, an increase of $72 million, or 24.9%, compared to 2015. The increase was primarily due to a 36.8% increase in the volume of KWHs purchased to meet customer demand, partially offset by a 12.5% decrease in the average cost per KWH purchased due to lower natural gas prices. Purchased power expense from non-affiliates was $289 million in 2015, an increase of $2 million, or 0.7%, compared to 2014. The increase was primarily due to a 28.1% increase in the volume of KWHs purchased to meet customer demand, partially offset by a 19.8% decrease in the average cost per KWH purchased due to lower natural gas prices.

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

Purchased Power - Affiliates

Purchased power expense from affiliates was $518 million in 2016, a decrease of $57 million, or 9.9%, compared to 2015. The decrease was primarily due to an 11.9% decrease in the volume of KWHs purchased due to the lower market cost of available energy as compared to Southern Company system resources, partially offset by a 6.2% increase in the average cost per KWH purchased. Purchased power expense from affiliates was $575 million in 2015, a decrease of $126 million, or 18.0%, compared to 2014. The decrease was primarily due to a decrease of 17.4% in the average cost per KWH purchased reflecting lower natural gas prices, partially offset by an 8.1% increase in the volume of KWHs purchased to meet customer demand.

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

Other Operations and Maintenance Expenses

In 2016, other operations and maintenance expenses increased $116 million, or 6.3%, compared to 2015. The increase was primarily due to a $37 million decrease in gains from sales of assets, a $36 million charge in connection with cost containment activities, a $30 million increase in overhead line maintenance, a $15 million increase in hydro and gas generation maintenance, a $10 million increase in customer accounts, service, and sales costs, and a $7 million increase in material costs related to higher generation volumes. The increase was partially offset by a decrease of $36 million in pension costs.

In 2015, other operations and maintenance expenses decreased $58 million, or 3.0%, compared to 2014. The decrease was primarily due to decreases of $51 million in transmission operating expenses, primarily due to gains from sales of assets and billing adjustments with integrated transmission system owners, $28 million in transmission and distribution overhead line maintenance, and $11 million in workers compensation and legal expense related to a lower volume of claims, partially offset by an increase of $33 million in employee benefits including pension costs.

See FUTURE EARNINGS POTENTIAL – "Other Matters" herein and Note 2 to the financial statements for additional information related to the cost containment activities and pension costs, respectively.

Depreciation and Amortization

Depreciation and amortization increased $9 million, or 1.1%, in 2016 compared to 2015. The increase was primarily due to a $34 million increase related to additional plant in service and a $9 million increase in other cost of removal, partially offset by an $18 million decrease related to amortization of nuclear construction financing costs that was completed in December 2015 and a decrease of $16 million related to unit retirements.

Depreciation and amortization remained flat in 2015 compared to 2014 primarily due to a $16 million decrease related to unit retirements and a $9 million decrease related to other cost of removal obligations, largely offset by a $23 million increase related to additional plant in service.

See Note 1 to the financial statements under "Depreciation and Amortization" for additional information.

Taxes Other Than Income Taxes

In 2016, taxes other than income taxes increased $14 million, or 3.6%, compared to 2015 primarily due to increases of $7 million in property taxes as a result of an increase in the assessed value of property and $4 million in payroll taxes.

In 2015, taxes other than income taxes decreased $18 million, or 4.4%, compared to 2014 primarily due to decreases of $15 million in municipal franchise fees related to lower retail revenues and $5 million in payroll taxes.

Interest Expense, Net of Amounts Capitalized

In 2016, interest expense, net of amounts capitalized increased $25 million, or 6.9%, compared to the prior year. The increase was primarily due to a $34 million increase in interest due to additional long-term borrowings from the FFB and higher interest rates on obligations for pollution control revenue bonds remarketed in 2015, partially offset by an increase of $4 million in AFUDC debt.

In 2015, interest expense, net of amounts capitalized increased $15 million, or 4.3%, compared to the prior year. The increase was primarily due to a $23 million increase in interest due to additional long-term debt borrowings from the FFB, partially offset by an $11 million decrease in interest on senior notes due to redemptions and maturities.

Other Income (Expense), Net

In 2016, other income (expense), net decreased $23 million compared to the prior year primarily due to decreases of $8 million in customer contributions in aid of construction, $6 million in wholesale operating fee revenue, and $4 million in gains on purchases of state tax credits.

In 2015, other income (expense), net increased $38 million compared to the prior year primarily due to increases of $9 million in wholesale operating fee revenue and $9 million in customer contributions in aid of construction, as well as a $9 million decrease in donations.

Income Taxes

Income taxes increased $11 million, or 1.4%, in 2016 compared to the prior year primarily due to higher pre-tax earnings, partially offset by decreases in non-deductible book depreciation and increased state investment tax credits.

Income taxes increased $40 million, or 5.5%, in 2015 compared to the prior year primarily due to higher pre-tax earnings and the recognition in 2014 of tax benefits related to emissions allowances and state apportionment.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. The completion and subsequent operation of ongoing construction projects, primarily Plant Vogtle Units 3 and 4, also are major factors. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies, increasing volumes of electronic commerce transactions, and higher multi-family home construction. Earnings are subject to a variety of other factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is primarily driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, which may impact future earnings. Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals, including any potential changes to the availability of nuclear PTCs, is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the Company's financial statements.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. The Company's Environmental Compliance Cost Recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2016, the Company had invested approximately $5.2 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $0.2 billion, $0.3 billion, and $0.4 billion for 2016, 2015, and 2014, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $1.2 billion from 2017 through 2021, with annual totals of approximately $0.4 billion, $0.3 billion, $0.1 billion, $0.2 billion, and $0.2 billion for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Cost of Removal" for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the Company's fuel mix; and environmental remediation requirements. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, 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.

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 implementation strategy for the MATS rule included emission controls, retirements, and fuel conversions at affected units. All of the Company's units that are subject to the MATS rule completed the measures necessary to achieve compliance with this rule or were retired prior to or during 2016.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a revised eight-hour ozone NAAQS and published its final area designations in 2012. The only area within the Company's service territory designated as an ozone nonattainment area for the 2008 standard is a 15-county area within metropolitan Atlanta, which on December 23, 2016, the EPA proposed to redesignate to attainment. In October 2015, the EPA published a more stringent eight-hour ozone NAAQS. This new standard could potentially require additional emission controls, improvements in control efficiency, and operational fuel changes and could affect the siting of new generating facilities. States were required to recommend area designations by October 2016, and the only area within the

Company's service territory that was proposed for designation is an eight-county area within the Atlanta metropolitan area in Georgia. The EPA is expected to finalize area designations by October 2017.

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

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

In 2014, the EPA proposed to delete from the Alabama State Implementation Plan (SIP) the Alabama opacity rule that the EPA approved in 2008, which provides operational flexibility to affected units, including units owned by SEGCO, which is jointly owned by Alabama Power and the Company. In 2013, the U.S. Court of Appeals for the Eleventh Circuit ruled in favor of Alabama Power and the Company and vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA's latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act. Alabama Power and the Company believe this interpretation of the Clean Air Act to be incorrect. If finalized, this proposed action could affect unit availability and result in increased operations and maintenance costs for SEGCO. See Note 4 to the financial statements for additional information regarding SEGCO.

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide (NO_x) emissions from power plants in two phases – Phase 1 in 2015 and Phase 2 in 2017. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone season NO_x program, beginning in 2017, and establishes more stringent ozone-season emissions budgets in Alabama. The State of Georgia's emission budget was not affected by the revisions, but interstate emissions trading is restricted unless the state decides to voluntarily adopt a reduced budget. Georgia and Alabama are also in the CSAPR annual SO_2 and NO_x programs.

The EPA finalized regional haze regulations in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. On December 14, 2016, the EPA finalized revisions to the regional haze regulations. These regulations establish a deadline of July 31, 2021 for states to submit revised SIPs to the EPA demonstrating reasonable progress toward the statutory goal of achieving natural background conditions by 2064. State implementation of the reasonable progress requirements defined in this final rule could require further reductions in SO_2 or NO_x emissions.

In June 2015, the EPA published a final rule requiring certain states (including Georgia and Alabama) to revise or remove the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM), and the State of Georgia has submitted proposed SIP revisions in response to the rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. These regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates or through PPAs. The ultimate impact of the eight-hour ozone and SO_2 NAAQS, Alabama opacity rule, CSAPR, regional haze regulations, and SSM rule will depend on various factors, such as implementation, adoption, or other action at the state level, and the outcome of pending and/or future legal challenges, and cannot be determined at this time.

Water Quality

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

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

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

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

Coal Combustion Residuals

The Company currently manages CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at 12 current or former electric generating plants. In addition to on-site storage, the Company also sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the State of Georgia has its own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

The CCR Rule became effective in October 2015. The CCR Rule regulates the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not automatically require closure of CCR Units but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the required closure of a CCR Unit. On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation Act (WIIN Act). The WIIN Act allows states to establish permit programs for implementing the CCR Rule, if the EPA approves the program, and allows for federal permits and EPA enforcement where a state permitting program does not exist. On October 26, 2016, the Georgia Department of Natural Resources approved amendments to its state solid waste regulations to incorporate the requirements of the CCR Rule and establish additional requirements for all of the Company's onsite storage units consisting of landfills and surface impoundments.

Based on current cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, the Company has recorded incremental AROs related to the CCR Rule. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, the Company expects to continue to periodically update these estimates. The Company has posted closure and post-closure care plans to its public website as required by the CCR Rule; however, the ultimate impact of the CCR Rule will depend on the results of initial and ongoing minimum criteria assessments and implementation of state or federal permit programs. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information regarding the Company's AROs as of December 31, 2016.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Notes 1 and 3 to the financial statements under "Environmental Remediation Recovery" and "Environmental Matters – Environmental Remediation," respectively, for additional information.

Global Climate Issues

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

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

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

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2015 greenhouse gas emissions were approximately 32 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2016 greenhouse gas emissions on the same basis is approximately 33 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 electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

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

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

Retail Regulatory Matters

The Company's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. The Company currently recovers its costs from the regulated retail business through the 2013 ARP, which includes traditional base tariff rates, Demand-Side Management (DSM) tariffs, ECCR tariffs, and Municipal Franchise Fee (MFF) tariffs. In addition, financing costs related to the construction of Plant Vogtle Units 3 and 4 are being collected through the NCCR tariff and fuel costs are collected through separate fuel cost recovery tariffs. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Rate Plans

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC on April 14, 2016, the 2013 ARP will continue in effect until December 31, 2019, and the Company will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, the Company and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60/40 basis with their respective customers; thereafter, all merger savings will be retained by customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information regarding the 2013 ARP.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2015 and 2016 as follows: (1) traditional base tariff rates by approximately $107 million and $49 million, respectively; (2) ECCR tariff by approximately $23 million and $75 million, respectively; (3) DSM tariffs by approximately $3 million in each year; and (4) MFF tariff by approximately $3 million and $13 million, respectively, for a total increase in base revenues of approximately $136 million and $140 million, respectively.

Under the 2013 ARP, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, the Company's retail ROE exceeded 12.00%, and the Company refunded to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, the Company's retail ROE was within the allowed retail ROE range. In 2016, the Company's retail ROE exceeded 12.00%, and the Company expects to refund to retail customers approximately $40 million, subject to review and approval by the Georgia PSC. The ultimate outcome of this matter cannot be determined at this time.

Renewables

In 2014, the Georgia PSC approved the Company's application for the certification of two PPAs executed in 2013 for the purchase of energy from two wind farms in Oklahoma with capacity totaling 250 MWs that began in 2016 and have 20-year terms.

As part of the Georgia Power Advanced Solar Initiative (ASI), in 2014, the Georgia PSC approved PPAs executed since April 2015 for the purchase of energy from 555 MWs of solar capacity that began in 2015 and 2016 and have terms ranging from 20 to 30 years. As a result of certain acquisitions by Southern Power, 249 MWs of this contracted capacity is being provided from solar facilities owned by Southern Power through five PPAs that began in 2016. Ownership of any associated renewable energy credits (REC) is specified in each respective PPA. The party that owns the RECs retains the right to use them.

In 2014, the Georgia PSC approved the Company's request to build, own, and operate 30-MW solar generation facilities at three U.S. Army bases and one U.S. Navy base by the end of 2016. One of the four solar generation facilities began commercial operation in December 2015 and the remaining three began in the fourth quarter 2016. In December 2015, the Georgia PSC approved the Company's request to build, own, and operate a 31-MW solar generation facility at a U.S. Marine Corps base that is expected to begin commercial operation by summer 2017 and a 15-MW solar generation facility at a yet-to-be-determined U.S. military base. The ultimate outcome of this matter cannot be determined at this time.

Two PPAs for biomass generation capacity of 58 MWs each were executed in June 2015 and November 2015 and are expected to begin in 2019.

See "Integrated Resource Plan" herein for additional information on renewables.

Integrated Resource Plan

See "Environmental Matters" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent limitations guidelines for steam electric power plants, and additional regulations of CCR and CO_2; and the Company's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations.

On July 28, 2016, the Georgia PSC approved the 2016 IRP including the decertification and retirement of Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs), as well as the decertification of the Intercession City unit (143 MWs total capacity). On August 2, 2016, the Plant Mitchell and Plant Kraft units were retired. On August 31, 2016, the Company sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved the Company's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.

The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in the Company's 2019 base rate case.

The Georgia PSC also approved the Renewable Energy Development Initiative to procure an additional 1,200 MWs of renewable resources primarily utilizing market-based prices established through a competitive bidding process with expected in-service dates between 2018 and 2021. Additionally, 200 MWs of self-build capacity for use by the Company was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

The Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear as an option at a future generation site in Stewart County, Georgia. The timing of cost recovery will be determined by the Georgia PSC in a future base rate case. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In December 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016. On May 17, 2016, the Georgia PSC approved the Company's request to further lower annual billings by approximately $313 million effective June 1, 2016. On December 6, 2016, the Georgia PSC approved the delay of the Company's next fuel case, which was previously scheduled to be filed by February 28, 2017. The Georgia PSC will review the Company's cumulative over or under recovered fuel balance no later than September 1, 2018 and evaluate the need to file a fuel case unless the Company deems it necessary to file a fuel case at an earlier time. Under an Interim Fuel Rider, the Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds $200 million.

The Company's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 48-month time horizon effective January 1, 2016.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

Storm Damage Recovery

As of December 31, 2016, the balance in the Company's regulatory asset related to storm damage was $206 million. During October 2016, Hurricane Matthew caused significant damage to the Company's transmission and distribution facilities. As of December 31, 2016, the Company had recorded incremental restoration cost related to this hurricane of $121 million, of which approximately $116 million was charged to the storm damage reserve and the remainder was capitalized. The Company is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, to the storm damage reserve to cover the operations and maintenance costs of damages from major storms to its transmission and distribution facilities, which is recoverable through base rates. The rate of recovery of storm damage costs after December 31, 2019 is expected to be adjusted in the Company's 2019 base rate case. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on the Company's financial statements. See Note 1 to the financial statements under "Storm Damage Recovery" for additional information regarding the Company's storm damage reserve.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., which was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. (WECTEC) (Westinghouse and WECTEC, collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to an aggregate cap of 10% of the contract price, or approximately $920 million to $930 million. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which the Company has not been notified have occurred) with maximum additional capital costs under this provision attributable to the Company (based on the Company's ownership interest) of approximately $114 million. Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement.

Certain obligations of Westinghouse have been guaranteed by Toshiba Corporation (Toshiba), Westinghouse's parent company. In the event of certain credit rating downgrades of Toshiba, Westinghouse is required to provide letters of credit or other credit enhancement. In December 2015, Toshiba experienced credit rating downgrades and Westinghouse provided the Vogtle Owners with $920 million of letters of credit. These letters of credit remain in place in accordance with the terms of the Vogtle 3 and 4 Agreement.

On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a substantial goodwill impairment charge at Westinghouse attributed to increased cost estimates to complete its U.S. nuclear projects, including Plant Vogtle Units 3 and 4. Toshiba also warned that it will likely be in a negative equity position as a result of the charges. At the same time, Toshiba reaffirmed its commitment to its U.S. nuclear projects with implementation of management changes and increased oversight. An inability or failure by the Contractor to perform its obligations under the Vogtle 3 and 4 Agreement could have a material impact on the construction of Plant Vogtle Units 3 and 4.

Under the terms of the Vogtle 3 and 4 Agreement, the Contractor does not have a right to terminate the Vogtle 3 and 4 Agreement for convenience. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. In the event of an abandonment of work by the Contractor, the maximum liability of the Contractor under the Vogtle 3 and 4 Agreement is increased significantly, but remains subject to limitations. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for convenience, provided that the Vogtle Owners will be required to pay certain termination costs.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved an NCCR tariff of $368 million for 2014, as well as increases to the NCCR tariff of approximately $27 million and $19 million effective January 1, 2015 and 2016, respectively.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. In accordance with the 2009 certification order, the Company requested amendments to the Plant Vogtle Units 3 and 4 certificate in both the February 2013 (eighth VCM) and February 2015 (twelfth VCM) filings, when projected construction capital costs to be borne by the Company increased by 5% above the certified costs and estimated in-service dates were extended. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between the Company and the Georgia PSC Staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and the Company. In April 2015, the Georgia PSC recognized that the certified cost and the 2013 Stipulation did not constitute a cost recovery cap and deemed the amendment requested in the February 2015 filing unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation.

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including litigation that was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation). Effective December 31, 2015, the Company, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will commence if the nuclear fuel loading date for each unit does not occur by December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4; and (v) provide that the Company, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million, of which approximately $263 million had been paid as of December 31, 2016. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs are reflected in the Company's current in-service forecast of $5.440 billion. Further, as part of the settlement and Westinghouse's acquisition of WECTEC: (i) Westinghouse engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor and (ii) the Vogtle Owners, Chicago Bridge & Iron Co, N.V., and The Shaw Group Inc. entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving the following prudence matters: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report will be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement is reasonable and prudent and none of the amounts paid or to be paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) financing costs on verified and approved capital costs will be deemed prudent provided they are incurred prior to December 31, 2019 and December 31, 2020 for Plant Vogtle Units 3 and 4, respectively; and (iv) (a) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above the Company's current forecast of $5.440 billion, (b) capital costs incurred up to the Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (c) the Company would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent. Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating the NCCR tariff will remain at $4.418 billion. Construction capital costs above $4.418 billion will accrue AFUDC through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be the Company's average cost of long-term debt. If the Georgia PSC adjusts the Company's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be the Company's average cost of long-term debt.

Under the terms of the Vogtle Cost Settlement Agreement, Plant Vogtle Units 3 and 4 will be placed into retail rate base on December 31, 2020 or when placed in service, whichever is later. The Georgia PSC will determine for retail ratemaking purposes the process of transitioning Plant Vogtle Units 3 and 4 from a construction project to an operating plant no later than the Company's base rate case required to be filed by July 1, 2019.

The Georgia PSC has approved fifteen VCM reports covering the periods through June 30, 2016, including construction capital costs incurred, which through that date totaled $3.7 billion. The Company expects to file the sixteenth VCM report, covering the period from July 1 through December 31, 2016, requesting approval of $222 million of construction capital costs incurred during that period, with the Georgia PSC by February 28, 2017. The Company's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.9 billion as of December 31, 2016, and the Company had incurred $1.3 billion in financing costs through December 31, 2016.

As of December 31, 2016, the Company had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between the Company and the DOE and a multi-advance credit facility among the Company, the DOE, and the FFB. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, and mandatory prepayment events.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise as construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

In addition to Toshiba's reaffirmation of its commitment, the Contractor provided the Company with revised forecasted in-service dates of December 2019 and September 2020 for Plant Vogtle Units 3 and 4, respectively. The Company is currently reviewing a preliminary summary schedule supporting these dates that ultimately must be reconciled to a detailed integrated project schedule. As construction continues, the risk remains that challenges with Contractor performance including labor productivity, fabrication, delivery, assembly, and installation of plant systems, structures, and components, or other issues could arise and may further impact project schedule and cost. The Company expects the Contractor to employ mitigation efforts and believes the Contractor is responsible for any related costs under the Vogtle 3 and 4 Agreement. The Company estimates its financing costs for Plant Vogtle Units 3 and 4 to be approximately $30 million per month, with total construction period financing costs of approximately $2.5 billion. Additionally, the Company estimates its owner's costs to be approximately $6 million per month, net of delay liquidated damages.

The revised forecasted in-service dates are within the timeframe contemplated in the Vogtle Cost Settlement Agreement and would enable both units to qualify for production tax credits the IRS has allocated to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021. The net present value of the production tax credits is estimated at approximately $400 million per unit.

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

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

Income Tax Matters

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of bonus depreciation included in the PATH Act is expected to result in approximately $300 million of positive cash flows for the 2016 tax year and approximately $210 million for the 2017 tax year. See Note 5 to the financial statements for additional information.

Other Matters

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

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

The Company regularly evaluates its operations and costs. Primarily in response to changing customer expectations and payment patterns, including electronic payments and alternative payment locations, and on-going efforts to increase overall operating efficiencies, the Company initiated cost containment activities throughout the enterprise in July 2016, including the closure of 104 local offices and an employee attrition plan affecting approximately 300 positions. Charges associated with the cost containment activities did not have a material impact on the Company's results of operations, financial position, or cash flows. The cost containment activities are expected to reduce operating costs in 2017.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Utility Regulation

The Company is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

Asset Retirement Obligations

AROs are computed as the fair value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily relates to the decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, and facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

The Company previously recorded AROs as a result of state requirements in Georgia which closely align with the requirements of the CCR Rule discussed above. The cost estimates are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals" herein for additional information.

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

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

Pension and Other Postretirement Benefits

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

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate for each plan developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. For 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $35 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $10 million or less change in total annual benefit expense and a $147 million or less change in projected obligations.

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

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

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

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

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

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

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

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 12 to the financial statements for disclosures impacted by ASU 2016-09.

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

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2016. 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 build new generation facilities, including Plant Vogtle Units 3 and 4, to maintain existing generation facilities, to comply with environmental regulations including adding environmental modifications to existing generating units, to expand and improve transmission and distribution facilities, 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 2017 through 2019, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through securities issuances, capital contributions from Southern Company, borrowings from financial institutions, and borrowings through the FFB. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and nuclear decommissioning trust funds increased in value as of December 31, 2016 as compared to December 31, 2015. On December 19, 2016, the Company voluntarily contributed $287 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated during 2017. The Company also funded approximately $5 million to its nuclear decommissioning trust funds in 2016. See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $2.4 billion in 2016, a decrease of $92 million from 2015, primarily due to the voluntary contribution to the qualified pension plan, partially offset by the timing of vendor payments. Net cash provided from operating activities totaled $2.5 billion in 2015, an increase of $154 million from 2014, primarily due to increased fuel cost recovery, partially offset by the timing of vendor payments.

Net cash used for investing activities totaled $2.3 billion, $1.9 billion, and $2.2 billion in 2016, 2015, and 2014, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities; and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years has been provided from operating activities, capital contributions from Southern Company, and the issuance of debt. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information.

Net cash used for financing activities totaled $142 million, $530 million, and $163 million for 2016, 2015, and 2014, respectively. The decrease in cash used in 2016 compared to 2015 was primarily due to higher capital contributions from Southern Company, a decrease in redemptions and maturities of senior notes, and an increase in short-term debt, partially offset by higher common stock dividends and a decrease in borrowings from the FFB for construction of Plant Vogtle Units 3 and 4. The increase in cash used in 2015 compared to 2014 was primarily due to the redemption and maturity of senior notes in 2015. 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 2016 included an increase in property, plant, and equipment of $1.6 billion to comply with environmental standards and construction of generation, transmission, and distribution facilities, increases in other regulatory assets, deferred of $622 million and current and deferred ARO liabilities of $616 million primarily related to changes in ash pond closure strategy, an increase of $373 million in accumulated deferred income taxes primarily as a result of bonus depreciation, and an increase of $357 million in long-term debt due to issuances exceeding maturities. See Note 1 to the financial statements for additional information.

The Company's ratio of common equity to total capitalization plus short-term debt, was 50.0% at December 31, 2016 and 49.9% at December 31, 2015. 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, borrowings from the FFB, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approvals, prevailing market conditions, and other factors.

The Company may make borrowings through a loan guarantee agreement (Loan Guarantee Agreement) between the Company and the DOE, the proceeds of which may be used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Loan Guarantee Agreement (Eligible Project Costs). Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by the Company under a multi-advance credit facility (FFB Credit Facility) among the Company, the DOE, and the FFB. Eligible Project Costs incurred through December 31, 2016 would allow for borrowings of up to $2.7 billion under the FFB Credit Facility, of which the Company has borrowed $2.6 billion. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement and Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

At December 31, 2016, the Company's current liabilities exceeded current assets by $1.5 billion. The Company's current liabilities frequently exceed current assets because of scheduled maturities of long-term debt and the periodic use of short-term debt as a funding source, as well as significant seasonal fluctuations in cash needs.

The Company intends to utilize operating cash flows, as well as FFB borrowings, commercial paper, lines of credit, bank notes, and external securities issuances, as market conditions permit, and equity contributions from Southern Company to fund its short-term capital needs. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs.

At December 31, 2016, the Company had approximately $3 million of cash and cash equivalents. A committed credit arrangement with banks at December 31, 2016 was $1.75 billion of which $1.73 billion was unused. This credit arrangement expires in 2020.

This bank credit arrangement contains a covenant that limits debt levels and contains a cross acceleration provision to other indebtedness (including guarantee obligations) of the Company. Such cross acceleration provision to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2016, the Company was in compliance with this covenant. This bank credit arrangement does not contain a material adverse change clause at the time of borrowing.

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

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

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was approximately $868 million. In addition, at December 31, 2016, the Company had $250 million of fixed rate pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months.

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

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period			Short-term Debt During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate		Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)			*(in millions)*		*(in millions)*
December 31, 2016:						
Commercial paper	**$ 392**	**1.1%**		**$ 87**	**0.8%**	**$ 443**
December 31, 2015:						
Commercial paper	$ 158	0.6%		$ 234	0.3%	$ 678
Short-term bank debt	—	—%		62	0.8%	250
Total	$ 158	0.6%		$ 296	0.4%	
December 31, 2014:						
Commercial paper	$ 156	0.3%		$ 280	0.2%	$ 703
Short-term bank debt	—	—%		56	0.9%	400
Total	$ 156	0.3%		$ 336	0.3%	

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2016, 2015, and 2014.

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

Financing Activities

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

Senior Notes

In March 2016, the Company issued $325 million aggregate principal amount of Series 2016A 3.25% Senior Notes due April 1, 2026 and $325 million aggregate principal amount of Series 2016B 2.40% Senior Notes due April 1, 2021. An amount equal to the proceeds from the Series 2016A 3.25% Senior Notes due April 1, 2026 is being allocated to eligible green expenditures, including financing of or investments in solar generating facilities or electric vehicle charging infrastructure, or payments under PPAs served by solar or wind generating facilities. The proceeds from the Series 2016B 2.40% Senior Notes due April 1, 2021 were used to repay at maturity $250 million aggregate principal amount of the Company's Series 2013B Floating Rate Senior Notes due March 15, 2016, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In April 2016, the Company's $250 million aggregate principal amount of Series 2011B 3.00% Senior Notes were repaid at maturity.

In August 2016, the Company's $200 million aggregate principal amount of Series 2013C Floating Rate Senior Notes were repaid at maturity.

Pollution Control Revenue Bonds

In January 2016, $4.085 million aggregate principal amount of Savannah Economic Development Authority Pollution Control Revenue Bonds (Savannah Electric and Power Company Project), First Series 1993 were repaid at maturity.

DOE Loan Guarantee Borrowings

In June and December 2016, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $300 million and $125 million, respectively. The interest rate applicable to the $300 million principal amount is 2.571% and the interest rate applicable to the $125 million principal amount is 3.142%, both for interest periods that extend to the final maturity date of February 20, 2044. The proceeds were used to reimburse the Company for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4.

Under the Loan Guarantee Agreement, the Company is subject to customary events of default, as well as cross-defaults to other indebtedness and events of default relating to any failure to make payments under the engineering, procurement, and construction contract, as amended, relating to Plant Vogtle Units 3 and 4 or certain other agreements providing intellectual property rights for Plant Vogtle Units 3 and 4. The Loan Guarantee Agreement also includes events of default specific to the DOE loan guarantee program, including the failure of the Company or Southern Nuclear to comply with requirements of law or DOE loan guarantee program requirements. In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and the Company will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information.

Credit Rating Risk

At December 31, 2016, the Company did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, transmission, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at December 31, 2016 were as follows:

Credit Ratings	**Maximum Potential Collateral Requirements**
	(in millions)
At BBB- and/or Baa3	$ 93
Below BBB- and/or Baa3	$ 1,258

Included in these amounts are certain agreements that could require collateral in the event that the Company or Alabama Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

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

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.8 billion of long-term variable interest rate exposure at January 1, 2017 was 1.91%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $18 million at January 1, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Georgia PSC. The Company had no material change in market risk exposure for the year ended December 31, 2016 when compared to the December 31, 2015 reporting period.

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

	2016 Changes	2015 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (13)**	$ (20)
Contracts realized or settled:		
Swaps realized or settled	**(2)**	2
Options realized or settled	**11**	18
Current period changes(*):		
Swaps	**31**	—
Options	**9**	(13)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ 36**	$ (13)

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

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

	2016	2015
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**128**	—
Commodity – Natural gas options	**27**	50
Total hedge volume	**155**	50

The weighted average swap contract cost below market prices was approximately $0.23 per mmBtu as of December 31, 2016. There were no swaps outstanding as of December 31, 2015. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2016 and 2015, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Through December 31, 2015, the Company's fuel-hedging program had a time horizon up to 24 months. Effective January 1, 2016, the Georgia PSC approved changes to the Company's hedging program allowing it to use an array of derivative instruments within a 48-month time horizon. Hedging gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2016 were as follows:

	Fair Value Measurements December 31, 2016		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	36	28	8
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ 36	$ 28	$ 8

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $2.6 billion for 2017, $2.7 billion for 2018, $2.1 billion for 2019, $1.9 billion for 2020, and $1.7 billion for 2021. These amounts include expenditures of approximately $0.7 billion, $0.5 billion, $0.3 billion, and $0.1 billion for the construction of Plant Vogtle Units 3 and 4 in 2017, 2018, 2019, and 2020, respectively. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.4 billion, $0.3 billion, $0.1 billion, $0.2 billion, and $0.2 billion for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from new, existing, 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 and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $0.3 billion for 2017 and $0.2 billion per year for 2018 through 2021. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for information regarding additional factors that may impact construction expenditures.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

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

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, other purchase commitments, and trusts are detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
			(in millions)		
Long-term debt[(a)] —					
Principal	$ 450	$ 1,250	$ 413	$ 8,533	$ 10,646
Interest	383	698	628	5,112	6,821
Preferred and preference stock dividends[(b)]	17	35	35	—	87
Financial derivative obligations[(c)]	1	6	1	—	8
Operating leases[(d)]	19	22	17	15	73
Capital leases[(d)]	9	17	7	—	33
Purchase commitments —					
Capital[(e)]	2,412	4,347	2,941	—	9,700
Fuel[(f)]	1,628	1,681	878	6,320	10,507
Purchased power[(g)]	320	595	539	2,543	3,997
Other[(h)]	108	141	126	361	736
Trusts —					
Nuclear decommissioning[(i)]	5	11	11	99	126
Pension and other postretirement benefit plans[(j)]	46	90	—	—	136
Total	$ 5,398	$ 8,893	$ 5,596	$ 22,983	$ 42,870

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2017, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

(c) Includes derivative liabilities related to energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.

(d) Excludes PPAs that are accounted for as leases and included in "Purchased power."

(e) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected in "Fuel" and "Other," respectively. At December 31, 2016, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "Retail Regulatory Matters – Nuclear Construction" herein for additional information.

(f) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2016.

(g) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. Includes a total of $292 million of biomass PPAs that is contingent upon the counterparties meeting specified contract dates for commercial operation. Subsequent to December 31, 2016, the specified contract dates for commercial operation were extended from 2017 to 2019 and may change further as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Renewables" herein for additional information.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

(i) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

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

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws regulating emissions, discharges, and disposal to air, water, and land, and also changes in tax and other laws and regulations to which the Company is subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development, construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed;
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;

- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

STATEMENTS OF INCOME
For the Years Ended December 31, 2016, 2015, and 2014
Georgia Power Company 2016 Annual Report

	2016	2015	2014
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 7,772**	$ 7,727	$ 8,240
Wholesale revenues, non-affiliates	**175**	215	335
Wholesale revenues, affiliates	**42**	20	42
Other revenues	**394**	364	371
Total operating revenues	**8,383**	8,326	8,988
Operating Expenses:			
Fuel	**1,807**	2,033	2,547
Purchased power, non-affiliates	**361**	289	287
Purchased power, affiliates	**518**	575	701
Other operations and maintenance	**1,960**	1,844	1,902
Depreciation and amortization	**855**	846	846
Taxes other than income taxes	**405**	391	409
Total operating expenses	**5,906**	5,978	6,692
Operating Income	**2,477**	2,348	2,296
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(388)**	(363)	(348)
Other income (expense), net	**38**	61	23
Total other income and (expense)	**(350)**	(302)	(325)
Earnings Before Income Taxes	**2,127**	2,046	1,971
Income taxes	**780**	769	729
Net Income	**1,347**	1,277	1,242
Dividends on Preferred and Preference Stock	**17**	17	17
Net Income After Dividends on Preferred and Preference Stock	**$ 1,330**	$ 1,260	$ 1,225

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2016, 2015, and 2014
Georgia Power Company 2016 Annual Report

		2016		2015		2014
				(in millions)		
Net Income	**$**	**1,347**	$	1,277	$	1,242
Other comprehensive income (loss):						
Qualifying hedges:						
Changes in fair value, net of tax of $-, $(6), and $(3), respectively		**—**		(9)		(5)
Reclassification adjustment for amounts included in net income, net of tax of $2, $1, and $1, respectively		**2**		2		2
Total other comprehensive income (loss)		**2**		(7)		(3)
Comprehensive Income	**$**	**1,349**	$	1,270	$	1,239

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

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

	2016	2015	2014
		(in millions)	
Operating Activities:			
Net income	$ **1,347**	$ 1,277	$ 1,242
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**1,063**	1,029	1,019
Deferred income taxes	**383**	173	352
Allowance for equity funds used during construction	**(48)**	(40)	(45)
Retail fuel cost over-recovery — long-term	**—**	106	(44)
Pension and postretirement funding	**(287)**	(7)	(156)
Settlement of asset retirement obligations	**(123)**	(29)	(12)
Other deferred charges — affiliated	**(111)**	—	—
Other, net	**(10)**	10	70
Changes in certain current assets and liabilities —			
-Receivables	**60**	187	(248)
-Fossil fuel stock	**104**	37	303
-Prepaid income taxes	**—**	89	(216)
-Other current assets	**(38)**	(62)	(37)
-Accounts payable	**(42)**	(259)	16
-Accrued taxes	**131**	25	17
-Accrued compensation	**(5)**	(17)	62
-Other current liabilities	**1**	(2)	40
Net cash provided from operating activities	**2,425**	2,517	2,363
Investing Activities:			
Property additions	**(2,223)**	(2,091)	(2,023)
Nuclear decommissioning trust fund purchases	**(808)**	(985)	(671)
Nuclear decommissioning trust fund sales	**803**	980	669
Cost of removal, net of salvage	**(83)**	(71)	(65)
Change in construction payables, net of joint owner portion	**(35)**	217	(54)
Prepaid long-term service agreements	**(34)**	(66)	(70)
Sale of property	**10**	70	7
Other investing activities	**23**	2	1
Net cash used for investing activities	**(2,347)**	(1,944)	(2,206)
Financing Activities:			
Increase (decrease) in notes payable, net	**234**	2	(891)
Proceeds —			
Senior notes	**650**	500	—
FFB loan	**425**	1,000	1,200
Pollution control revenue bonds issuances and remarketings	**—**	409	40
Capital contributions from parent company	**594**	62	549
Short-term borrowings	**—**	250	—
Redemptions and repurchases —			
Senior notes	**(700)**	(1,175)	—
Pollution control revenue bonds	**(4)**	(268)	(37)
Short-term borrowings	**—**	(250)	—
Payment of common stock dividends	**(1,305)**	(1,034)	(954)
Other financing activities	**(36)**	(26)	(70)
Net cash used for financing activities	**(142)**	(530)	(163)
Net Change in Cash and Cash Equivalents	**(64)**	43	(6)
Cash and Cash Equivalents at Beginning of Year	**67**	24	30
Cash and Cash Equivalents at End of Year	$ **3**	$ 67	$ 24
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $20, $16, and $18 capitalized, respectively)	$ **375**	$ 353	$ 319
Income taxes (net of refunds)	**170**	506	507
Noncash transactions —			
Accrued property additions at year-end	**336**	387	154
Capital lease obligation	**—**	149	—

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

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

Assets	**2016**	2015
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 3**	$ 67
Receivables —		
Customer accounts receivable	**523**	541
Unbilled revenues	**224**	188
Joint owner accounts receivable	**57**	227
Income taxes receivable, current	**—**	114
Other accounts and notes receivable	**81**	57
Affiliated	**18**	18
Accumulated provision for uncollectible accounts	**(3)**	(2)
Fossil fuel stock	**298**	402
Materials and supplies	**479**	449
Prepaid expenses	**105**	230
Other regulatory assets, current	**193**	213
Other current assets	**38**	19
Total current assets	**2,016**	2,523
Property, Plant, and Equipment:		
In service	**33,841**	31,841
Less accumulated provision for depreciation	**11,317**	10,903
Plant in service, net of depreciation	**22,524**	20,938
Other utility plant, net	**—**	171
Nuclear fuel, at amortized cost	**569**	572
Construction work in progress	**4,939**	4,775
Total property, plant, and equipment	**28,032**	26,456
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**60**	64
Nuclear decommissioning trusts, at fair value	**814**	775
Miscellaneous property and investments	**46**	43
Total other property and investments	**920**	882
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**676**	679
Other regulatory assets, deferred	**2,774**	2,152
Other deferred charges and assets	**417**	173
Total deferred charges and other assets	**3,867**	3,004
Total Assets	**$ 34,835**	$ 32,865

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

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

Liabilities and Stockholder's Equity	**2016**	2015
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 460**	$ 712
Notes payable	**391**	158
Accounts payable —		
Affiliated	**438**	411
Other	**589**	750
Customer deposits	**265**	264
Accrued taxes —		
Accrued income taxes	**17**	12
Other accrued taxes	**390**	325
Accrued interest	**106**	99
Accrued compensation	**224**	205
Asset retirement obligations, current	**299**	179
Other regulatory liabilities, current	**31**	16
Over recovered regulatory clause revenues, current	**84**	10
Other current liabilities	**182**	154
Total current liabilities	**3,476**	3,295
Long-Term Debt (See accompanying statements)	**10,225**	9,616
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**6,000**	5,627
Deferred credits related to income taxes	**121**	105
Accumulated deferred investment tax credits	**256**	204
Employee benefit obligations	**703**	949
Asset retirement obligations, deferred	**2,233**	1,737
Other deferred credits and liabilities	**199**	347
Total deferred credits and other liabilities	**9,512**	8,969
Total Liabilities	**23,213**	21,880
Preferred Stock (See accompanying statements)	**45**	45
Preference Stock (See accompanying statements)	**221**	221
Common Stockholder's Equity (See accompanying statements)	**11,356**	10,719
Total Liabilities and Stockholder's Equity	**$ 34,835**	$ 32,865
Commitments and Contingent Matters (See notes)		

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

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

	2016	2015	**2016**	2015
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
Variable rates (0.76% to 0.83% at 1/1/16) due 2016	**$ —**	$ 450		
3.00% due 2016	**—**	250		
5.70% due 2017	**450**	450		
1.95% to 5.40% due 2018	**748**	747		
4.25% due 2019	**500**	502		
2.40% due 2021	**325**	—		
2.85% to 5.95% due 2022-2043	**4,175**	3,850		
Total long-term notes payable	**6,198**	6,249		
Other long-term debt —				
Pollution control revenue bonds —				
1.38% to 4.00% due 2022-2049	**952**	952		
Variable rate (0.22% at 1/1/16) due 2016	**—**	4		
Variable rates (0.77% to 0.87% at 1/1/17) due 2022-2053	**868**	868		
FFB loans —				
2.57% to 3.86% due 2020	**44**	37		
2.57% to 3.86% due 2021	**44**	37		
2.57% to 3.86% due 2022-2044	**2,537**	2,126		
Total other long-term debt	**4,445**	4,024		
Capitalized lease obligations	**169**	183		
Unamortized debt premium (discount), net	**(10)**	(10)		
Unamortized debt issuance expense	**(117)**	(118)		
Total long-term debt (annual interest requirement — $402 million)	**10,685**	10,328		
Less amount due within one year	**460**	712		
Long-term debt excluding amount due within one year	**10,225**	9,616	**46.8%**	46.7%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value — 6.125%				
Authorized — 50,000,000 shares				
Outstanding — 1,800,000 shares	**45**	45		
Non-cumulative preference stock				
$100 par value — 6.50%				
Authorized — 15,000,000 shares				
Outstanding — 2,250,000 shares	**221**	221		
Total preferred and preference stock (annual dividend requirement — $17 million)	**266**	266	**1.2**	1.3
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 9,261,500 shares	**398**	398		
Paid-in capital	**6,885**	6,275		
Retained earnings	**4,086**	4,061		
Accumulated other comprehensive loss	**(13)**	(15)		
Total common stockholder's equity	**11,356**	10,719	**52.0**	52.0
Total Capitalization	**$ 21,847**	$ 20,601	**100.0%**	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2016, 2015, and 2014
Georgia Power Company 2016 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, 2013	9	$ 398	$ 5,633	$ 3,565	$ (5)	$ 9,591
Net income after dividends on preferred and preference stock	—	—	—	1,225	—	1,225
Capital contributions from parent company	—	—	563	—	—	563
Other comprehensive income (loss)	—	—	—	—	(3)	(3)
Cash dividends on common stock	—	—	—	(954)	—	(954)
Other	—	—	—	(1)	—	(1)
Balance at December 31, 2014	9	398	6,196	3,835	(8)	10,421
Net income after dividends on preferred and preference stock	—	—	—	1,260	—	1,260
Capital contributions from parent company	—	—	79	—	—	79
Other comprehensive income (loss)	—	—	—	—	(7)	(7)
Cash dividends on common stock	—	—	—	(1,034)	—	(1,034)
Balance at December 31, 2015	**9**	**398**	**6,275**	**4,061**	**(15)**	**10,719**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**1,330**	**—**	**1,330**
Capital contributions from parent company	**—**	**—**	**610**	**—**	**—**	**610**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**2**	**2**
Cash dividends on common stock	**—**	**—**	**—**	**(1,305)**	**—**	**(1,305)**
Balance at December 31, 2016	**9**	**$ 398**	**$ 6,885**	**$ 4,086**	**$ (13)**	**$ 11,356**

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

Georgia Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern LINC, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – the Company, Alabama Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Hatch and Plant Vogtle. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

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

The Company is subject to regulation by the FERC and the Georgia PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

In June 2015, the Company identified an error affecting the billing to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing from January 1, 2013 to June 30, 2015. In the second quarter 2015, the Company recorded an out of period adjustment of approximately $75 million to decrease retail revenues, resulting in a decrease to net income of approximately $47 million. The Company evaluated the effects of this error on the interim and annual periods that included the billing error. Based on an analysis of qualitative and quantitative factors, the Company determined the error was not material to any affected period and, therefore, an amendment of previously filed financial statements was not required.

Recently Issued Accounting Standards

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

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

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

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

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

On March 30, 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 12 for disclosures impacted by ASU 2016-09.

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

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 $606 million, $585 million, and $555 million in 2016, 2015, and 2014, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services; general operations, management, and technical services; administrative services including procurement, accounting, employee relations, systems, and procedures services; strategic planning and budgeting services; and other services with respect to business, operations, and construction management. Costs for these services amounted to $666 million, $681 million, and $643 million in 2016, 2015, and 2014, respectively.

The Company has entered into several PPAs with Southern Power for capacity and energy. Expenses associated with these PPAs were $265 million, $179 million, and $144 million in 2016, 2015, and 2014, respectively. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has a joint ownership agreement with Gulf Power under which Gulf Power owns a 25% portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $8 million, $12 million, and $9 million in 2016, 2015, and 2014, respectively. See Note 4 for additional information.

In 2014, prior to Southern Company's acquisition of PowerSecure on May 9, 2016, the Company entered into agreements with PowerSecure to build solar power generation facilities at two U.S. Army bases, as approved by the Georgia PSC. On October 4, 2016, the two facilities began commercial operation. Payments of approximately $118 million made by the Company to PowerSecure under the agreements since 2014 are included in utility plant in service at December 31, 2016.

On September 1, 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. For the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016, transportation costs under this agreement were approximately $35 million.

Prior to Southern Company's acquisition of Southern Company Gas, SCS, as agent for the Company, had agreements with certain subsidiaries of Southern Company Gas to purchase natural gas. For the period subsequent to Southern Company's acquisition of Southern Company Gas through December 31, 2016, natural gas purchases made by the Company from Southern Company Gas' subsidiaries were approximately $10 million.

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 2016, 2015, or 2014.

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

Regulatory Assets and Liabilities

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

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

	2016	2015	Note
	(in millions)		
Retiree benefit plans	**$ 1,348**	$ 1,307	(a, j)
Deferred income tax charges	**681**	683	(b, j)
Loss on reacquired debt	**137**	150	(c, j)
Asset retirement obligations	**893**	411	(b, j)
Vacation pay	**91**	91	(d, j)
Cancelled construction projects	**44**	56	(e)
Remaining net book value of retired assets	**166**	171	(f)
Storm damage reserves	**206**	92	(g)
Other regulatory assets	**97**	110	(h)
Other cost of removal obligations	**3**	(31)	(b)
Deferred income tax credits	**(121)**	(105)	(b, j)
Other regulatory liabilities	**(39)**	(2)	(i, j)
Total regulatory assets (liabilities), net	**$ 3,506**	$ 2,933	

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

(a) Recovered and amortized over the average remaining service period which may range up to 13 years. See Note 2 for additional information.

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. Included in the deferred income tax assets is $26 million for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Georgia PSC, through 2022.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which currently does not exceed 36 years.

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

(e) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements are being amortized as approved by the Georgia PSC over periods not exceeding nine years or through 2022.

(f) Amortized as approved by the Georgia PSC over periods not exceeding 10 years or through 2024. The net book value of Plant Mitchell Unit 3 at December 31, 2016 was $12 million, which will continue to be amortized through December 31, 2019 as provided in the 2013 ARP. Amortization of the remaining net book value of Plant Mitchell Unit 3 at December 31, 2019, which is expected to be approximately $5 million, and $31 million related to obsolete inventories of certain retired units will be determined by the Georgia PSC in the 2019 base rate case. See Note 3 under "Retail Regulatory Matters – Integrated Resource Plan" for additional information.

(g) Previous under-recovery as of December 2013 is recorded and recovered or amortized as approved by the Georgia PSC through 2019. Amortization of $185 million related to the under-recovery from January 2014 through December 2016 will be determined by the Georgia PSC in the 2019 base rate case. See Note 3 for additional information.

(h) Comprised of several components including deferred nuclear outages, environmental remediation, building lease, and demand-side management tariff under-recovery. Deferred nuclear outages are recorded and recovered or amortized over the outage cycles of each nuclear unit, which does not exceed 24 months. The building lease is recorded and recovered or amortized as approved by the Georgia PSC through 2020. The amortization of environmental remediation and demand-side management tariff under-recovery of $46 million at December 31, 2016 will be determined by the Georgia PSC in the 2019 base rate case.

(i) Comprised primarily of fuel-hedging gains, which upon final settlement are refunded through the Company's fuel cost recovery mechanism.

(j) Generally not earning a return as they are excluded from rate base or are offset in rate base by a corresponding asset or liability.

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

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Federal ITCs utilized are deferred and amortized to income as a credit to reduce depreciation over the average life of the related property. The Company had $83 million in federal ITCs at December 31, 2016 that will expire by 2036. State ITCs are recognized in the period in which the credits are generated. The Company had state investment and other tax credit carryforwards totaling $345 million at December 31, 2016, which will expire between 2019 and 2027 and are expected to be fully utilized by 2023.

The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the cost of equity and debt funds used during construction.

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

	2016	2015
	(in millions)	
Generation	**$ 16,668**	$ 15,386
Transmission	**5,779**	5,355
Distribution	**9,553**	9,151
General	**1,813**	1,921
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 33,841**	$ 31,841

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch Units 1 and 2, respectively.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.8% in 2016, 2.7% in 2015, and 2.7% in 2014. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Under the terms of the 2013 ARP, the Company amortized approximately $14 million in each of 2014, 2015, and 2016 of its remaining regulatory liability related to other cost of removal obligations.

Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual and recovery of other retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for future obligations are reflected in the balance sheets as a regulatory liability and amounts to be recovered are reflected in the balance sheets as a regulatory asset.

The ARO liability primarily relates to the Company's ash ponds, landfills, and gypsum cells that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in April 2015 (CCR Rule). In addition, the Company has retirement obligations related to decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

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

	2016	2015
	(in millions)	
Balance at beginning of year	**$ 1,916**	$ 1,255
Liabilities incurred	**—**	6
Liabilities settled	**(123)**	(30)
Accretion	**77**	56
Cash flow revisions	**662**	629
Balance at end of year	**$ 2,532**	$ 1,916

The increase in cash flow revisions in 2016 is primarily related to changes to the Company's closure strategy for ash ponds, landfills, and gypsum cells AROs.

The increase in cash flow revisions in 2015 is primarily related to changes to the Company's ash ponds, landfills, and gypsum cells ARO closure dollar and timing estimates associated with the CCR Rule and revisions to the nuclear decommissioning AROs based on the latest decommissioning study.

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

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the IRS. While the

Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2016 and 2015, approximately $56 million and $76 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $58 million and $78 million at December 31, 2016 and 2015, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2016, investment securities in the Funds totaled $814 million, consisting of equity securities of $326 million, debt securities of $477 million, and $11 million of other securities. At December 31, 2015, investment securities in the Funds totaled $775 million, consisting of equity securities of $296 million, debt securities of $463 million, and $16 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $803 million, $980 million, and $669 million in 2016, 2015, and 2014, respectively, all of which were reinvested. For 2016, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $38 million, which included $14 million related to unrealized gains on securities held in the Funds at December 31, 2016. For 2015, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $3 million, which included $26 million related to unrealized losses on securities held in the Funds at December 31, 2015. For 2014, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $44 million, which included an immaterial amount related to unrealized gains and losses on securities held in the Funds at December 31, 2014. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning are based on the most current study performed in 2015. The site study costs and external trust funds for decommissioning as of December 31, 2016 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2075	2079
	(in millions)	
Site study costs:		
Radiated structures	$ 678	$ 568
Spent fuel management	160	147
Non-radiated structures	64	89
Total site study costs	$ 902	$ 804
External trust funds	$ 511	$ 303

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved annual decommissioning cost for ratemaking of $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4%. The Company expects the Georgia PSC to review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs in the Company's 2019 base rate case.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2016, 2015, and 2014, the average AFUDC rates were 6.9%, 6.5%, and 5.6%, respectively, and AFUDC capitalized was $68 million, $56 million, and $62 million, respectively. AFUDC, net of income taxes, was 4.6%, 3.9%, and 4.6% of net income after dividends on preferred and preference stock for 2016, 2015, and 2014, respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information on the inclusion of construction costs related to Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011.

Impairment of Long-Lived Assets and Intangibles

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

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Beginning January 1, 2014, the Company is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. As of December 31, 2016 and December 31, 2015, the balance in the regulatory asset related to storm damage was $206 million and $92 million, respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $176 million and $62 million included in other regulatory assets, deferred, respectively. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, costs related to storms are generally not expected to have a material impact on the Company's earnings. See Note 3 under "Retail Regulatory Matters – Storm Damage Recovery" for additional information.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. In December 2013, the Georgia PSC approved the 2013 ARP including the recovery of approximately $2 million annually through the environmental compliance cost recovery (ECCR) tariff. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's earnings. As of December 31, 2016, the balance of the environmental remediation liability was $17 million, with approximately $2 million included in other regulatory assets, current and approximately $33 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" for additional information.

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, and oil, as well as transportation and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other") and are measured at fair value. See Note 10 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statements of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

Beginning in 2016, the Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under netting arrangements. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2016.

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). On December 19, 2016, the Company voluntarily contributed $287 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Georgia PSC and the FERC. For the year ending December 31, 2017, no other postretirement trust contributions are expected.

Actuarial Assumptions

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

Assumptions used to determine net periodic costs:	**2016**	2015	2014
Pension plans			
Discount rate – benefit obligations	**4.65%**	4.18%	5.02%
Discount rate – interest costs	**3.86**	4.18	5.02
Discount rate – service costs	**5.03**	4.49	5.02
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**4.46**	3.59	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	**4.49%**	4.03%	4.85%
Discount rate – interest costs	**3.67**	4.03	4.85
Discount rate – service costs	**4.88**	4.39	4.85
Expected long-term return on plan assets	**6.27**	6.48	6.75
Annual salary increase	**4.46**	3.59	3.59

Assumptions used to determine benefit obligations:	**2016**	2015
Pension plans		
Discount rate	**4.40%**	4.65%
Annual salary increase	**4.46**	4.46
Other postretirement benefit plans		
Discount rate	**4.23%**	4.49%
Annual salary increase	**4.46**	4.46

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

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2016 were as follows:

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

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2016 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 55	$ 48
Service and interest costs	2	2

Pension Plans

The total accumulated benefit obligation for the pension plans was $3.5 billion at December 31, 2016 and $3.3 billion at December 31, 2015. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 3,615**	$ 3,781
Service cost	**70**	73
Interest cost	**136**	154
Benefits paid	**(164)**	(188)
Actuarial (gain) loss	**143**	(205)
Balance at end of year	**3,800**	3,615
Change in plan assets		
Fair value of plan assets at beginning of year	**3,196**	3,383
Actual return (loss) on plan assets	**288**	(13)
Employer contributions	**301**	14
Benefits paid	**(164)**	(188)
Fair value of plan assets at end of year	**3,621**	3,196
Accrued liability	**$ (179)**	$ (419)

At December 31, 2016, the projected benefit obligations for the qualified and non-qualified pension plans were $3.6 billion and $152 million, respectively. All pension plan assets are related to the qualified pension plan.

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

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 1,129**	$ 1,076
Other current liabilities	**(14)**	(13)
Employee benefit obligations	**(165)**	(406)

Presented below are the amounts included in regulatory assets at December 31, 2016 and 2015 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2017.

	2016	2015	Estimated Amortization in 2017
		(in millions)	
Prior service cost	**$ 17**	$ 8	**$ 3**
Net (gain) loss	**1,112**	1,068	**57**
Regulatory assets	**$ 1,129**	$ 1,076	

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

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 1,076**	$ 1,102
Net (gain) loss	**99**	59
Change in prior service costs	**14**	—
Reclassification adjustments:		
Amortization of prior service costs	**(5)**	(9)
Amortization of net gain (loss)	**(55)**	(76)
Total reclassification adjustments	**(60)**	(85)
Total change	**53**	(26)
Ending balance	**$ 1,129**	$ 1,076

Components of net periodic pension cost were as follows:

	2016	2015	2014
		(in millions)	
Service cost	**$ 70**	$ 73	$ 62
Interest cost	**136**	154	153
Expected return on plan assets	**(258)**	(251)	(228)
Recognized net (gain) loss	**55**	76	41
Net amortization	**5**	9	10
Net periodic pension cost	**$ 8**	$ 61	$ 38

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

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2016, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2017	$ 184
2018	190
2019	196
2020	202
2021	206
2022 to 2026	1,126

Other Postretirement Benefits

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

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 854**	$ 864
Service cost	**6**	7
Interest cost	**30**	34
Benefits paid	**(45)**	(45)
Actuarial (gain) loss	**(1)**	(22)
Plan amendment	**—**	12
Retiree drug subsidy	**3**	4
Balance at end of year	**847**	854
Change in plan assets		
Fair value of plan assets at beginning of year	**358**	395
Actual return (loss) on plan assets	**21**	(6)
Employer contributions	**17**	10
Benefits paid	**(42)**	(41)
Fair value of plan assets at end of year	**354**	358
Accrued liability	**$ (493)**	$ (496)

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

	2016	2015
	(in millions)	
Other regulatory assets, deferred	**$ 213**	$ 223
Employee benefit obligations	**(493)**	(496)

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

	2016	2015	**Estimated Amortization in 2017**
		(in millions)	
Prior service cost	**$ 6**	$ 8	**$ 1**
Net (gain) loss	**207**	215	**8**
Regulatory assets	**$ 213**	$ 223	

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

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 223**	$ 213
Net (gain) loss	**—**	9
Change in prior service costs	**—**	12
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	—
Amortization of net gain (loss)	**(9)**	(11)
Total reclassification adjustments	**(10)**	(11)
Total change	**(10)**	10
Ending balance	**$ 213**	$ 223

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

	2016	2015	2014
		(in millions)	
Service cost	**$ 6**	$ 7	$ 6
Interest cost	**30**	34	34
Expected return on plan assets	**(22)**	(24)	(25)
Net amortization	**10**	11	2
Net periodic postretirement benefit cost	**$ 24**	$ 28	$ 17

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

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2017	$ 54	$ (4)	$ 50
2018	56	(5)	51
2019	58	(5)	53
2020	59	(5)	54
2021	60	(6)	54
2022 to 2026	303	(32)	271

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

	Target	**2016**	2015
Pension plan assets:			
Domestic equity	26%	**29%**	30%
International equity	25	**22**	23
Fixed income	23	**29**	23
Special situations	3	**2**	2
Real estate investments	14	**13**	16
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	36%	**35%**	34%
International equity	24	**24**	27
Domestic fixed income	33	**35**	25
Global fixed income			8
Special situations	1	**1**	—
Real estate investments	4	**4**	4
Private equity	2	**1**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2016 and 2015. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

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

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

	Fair Value Measurements Using				
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity(*)	$ 686	$ 317	$ —	$ —	$ 1,003
International equity(*)	420	380	—	—	800
Fixed income:					
U.S. Treasury, government, and agency bonds	—	201	—	—	201
Mortgage- and asset-backed securities	—	4	—	—	4
Corporate bonds	—	338	—	—	338
Pooled funds	—	179	—	—	179
Cash equivalents and other	340	1	—	—	341
Real estate investments	106	—	—	394	500
Special situations	—	—	—	61	61
Private equity	—	—	—	188	188
Total	$ 1,552	$ 1,420	$ —	$ 643	$ 3,615

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

	Fair Value Measurements Using				
As of December 31, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity(*)	$ 565	$ 236	$ —	$ —	$ 801
International equity(*)	412	343	—	—	755
Fixed income:					
U.S. Treasury, government, and agency bonds	—	157	—	—	157
Mortgage- and asset-backed securities	—	69	—	—	69
Corporate bonds	—	394	—	—	394
Pooled funds	—	173	—	—	173
Cash equivalents and other	—	50	—	—	50
Real estate investments	103	—	—	421	524
Private equity	—	—	—	220	220
Total	$ 1,080	$ 1,422	$ —	$ 641	$ 3,143

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

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

	Fair Value Measurements Using				
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity(*)	$ 45	$ 9	$ —	$ —	$ 54
International equity(*)	11	37	—	—	48
Fixed income:					
U.S. Treasury, government, and agency bonds	—	5	—	—	5
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	9	—	—	9
Pooled funds	—	38	—	—	38
Cash equivalents and other	15	—	—	—	15
Trust-owned life insurance	—	162	—	—	162
Real estate investments	3	—	—	11	14
Special situations	—	—	—	2	2
Private equity	—	—	—	5	5
Total	$ 74	$ 260	$ —	$ 18	$ 352

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

As of December 31, 2015:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity[*]	$ 30	$ 36	$ —	$ —	$ 66
International equity[*]	12	41	—	—	53
Fixed income:					
U.S. Treasury, government, and agency bonds	—	5	—	—	5
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	12	—	—	12
Pooled funds	—	30	—	—	30
Cash equivalents and other	10	6	—	—	16
Trust-owned life insurance	—	158	—	—	158
Real estate investments	3	—	—	12	15
Private equity	—	—	—	7	7
Total	$ 55	$ 290	$ —	$ 19	$ 364

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

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2016, 2015, and 2014 were $27 million, $26 million, and $25 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

In 2011, plaintiffs filed a putative class action against the Company in the Superior Court of Fulton County, Georgia alleging that the Company's collection in rates of municipal franchise fees (all of which are remitted to municipalities) exceeded the amounts allowed in orders of the Georgia PSC and alleging certain state tort law claims. On November 16, 2016, the Georgia Court of Appeals reversed the trial court's previous dismissal of the case and remanded the case to the trial court for further proceedings. The Company has filed a petition for writ of certiorari with the Georgia Supreme Court. The Company believes the plaintiffs' claims have no merit and intends to vigorously defend itself in this matter. The ultimate outcome of this matter cannot be determined at this time.

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

Environmental Matters

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. See Note 1 under "Environmental Remediation Recovery" for additional information.

The Company's environmental remediation liability as of December 31, 2016 was $17 million. The Company has been designated or identified as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act, and assessment and potential cleanup of such sites is expected.

The ultimate outcome of these matters cannot be determined at this time; however, as a result of the Company's regulatory treatment for environmental remediation expenses described in Note 1 under "Environmental Remediation Recovery," these matters are not expected to have a material impact on the Company's financial statements.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with the Company that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Hatch and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

In 2014, the Court of Federal Claims entered a judgment in favor of the Company in its spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. In March 2015, the Company recovered approximately $18 million, based on its ownership interests, which was credited to accounts where the original costs were charged and reduced rate base, fuel, and cost of service for the benefit of customers.

In 2014, the Company filed additional lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2016 for any potential recoveries from the additional lawsuits. The final outcome of these matters cannot be determined at this time; however, no material impact on the Company's net income is expected.

On-site dry spent fuel storage facilities are operational at Plant Vogtle Units 1 and 2 and Plant Hatch. Facilities can be expanded to accommodate spent fuel through the expected life of each plant.

FERC Matters

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

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

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

Retail Regulatory Matters

Rate Plans

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC on April 14, 2016, the 2013 ARP will continue in effect until December 31, 2019, and the Company will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, the Company and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60/40 basis with their respective customers; thereafter, all merger savings will be retained by customers.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2015 and 2016 as follows: (1) traditional base tariff rates by approximately $107 million and $49 million, respectively; (2) ECCR tariff by approximately $23 million and $75 million, respectively; (3) Demand-Side Management tariffs by approximately $3 million in each year; and (4) Municipal Franchise Fee tariff by approximately $3 million and $13 million, respectively, for a total increase in base revenues of approximately $136 million and $140 million, respectively.

Under the 2013 ARP, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, the Company's retail ROE exceeded 12.00%, and the Company refunded to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, the Company's retail ROE was within the allowed retail ROE range. In 2016, the Company's retail ROE exceeded 12.00%, and the Company expects to refund to retail customers approximately $40 million, subject to review and approval by the Georgia PSC. The ultimate outcome of this matter cannot be determined at this time.

Integrated Resource Plan

On July 28, 2016, the Georgia PSC approved the 2016 IRP including the decertification and retirement of Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs), as well as the decertification of the Intercession City unit (143 MWs total capacity). On August 2, 2016, the Plant Mitchell and Plant Kraft units were retired. On August 31, 2016, the Company sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved the Company's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.

The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in the Company's 2019 base rate case.

The Georgia PSC also approved the Renewable Energy Development Initiative to procure an additional 1,200 MWs of renewable resources primarily utilizing market-based prices established through a competitive bidding process with expected in-service dates between 2018 and 2021. Additionally, 200 MWs of self-build capacity for use by the Company was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

The Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear as an option at a future generation site in Stewart County, Georgia. The timing of cost recovery will be determined by the Georgia PSC in a future base rate case. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In December 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016. On May 17, 2016, the Georgia PSC approved the Company's request to further lower annual billings by approximately $313 million effective

June 1, 2016. On December 6, 2016, the Georgia PSC approved the delay of the Company's next fuel case, which was previously scheduled to be filed by February 28, 2017. The Georgia PSC will review the Company's cumulative over or under recovered fuel balance no later than September 1, 2018 and evaluate the need to file a fuel case unless the Company deems it necessary to file a fuel case at an earlier time. Under an Interim Fuel Rider, the Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds $200 million.

The Company's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 48-month time horizon effective January 1, 2016.

The Company's over recovered fuel balance totaled approximately $84 million at December 31, 2016 and is included in over recovered regulatory clause revenues, current. At December 31, 2015, the Company's over recovered fuel balance totaled approximately $116 million, including $10 million in over recovered regulatory clause revenues, current and $106 million in other deferred credits and liabilities.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

Storm Damage Recovery

As of December 31, 2016, the balance in the Company's regulatory asset related to storm damage was $206 million. During October 2016, Hurricane Matthew caused significant damage to the Company's transmission and distribution facilities. As of December 31, 2016, the Company had recorded incremental restoration cost related to this hurricane of $121 million, of which approximately $116 million was charged to the storm damage reserve and the remainder was capitalized. The Company is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, to the storm damage reserve to cover the operations and maintenance costs of damages from major storms to its transmission and distribution facilities, which is recoverable through base rates. The rate of recovery of storm damage costs after December 31, 2019 is expected to be adjusted in the Company's 2019 base rate case. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on the Company's financial statements. See Note 1 under "Storm Damage Recovery" for additional information regarding the Company's storm damage reserve.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., which was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. (WECTEC) (Westinghouse and WECTEC, collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to an aggregate cap of 10% of the contract price, or approximately $920 million to $930 million. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which the Company has not been notified have occurred) with maximum additional capital costs under this provision attributable to the Company (based on the Company's ownership interest) of approximately $114 million. Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement.

Certain obligations of Westinghouse have been guaranteed by Toshiba Corporation (Toshiba), Westinghouse's parent company. In the event of certain credit rating downgrades of Toshiba, Westinghouse is required to provide letters of credit or other credit enhancement. In December 2015, Toshiba experienced credit rating downgrades and Westinghouse provided the Vogtle Owners with $920 million of letters of credit. These letters of credit remain in place in accordance with the terms of the Vogtle 3 and 4 Agreement.

On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a substantial goodwill impairment charge at Westinghouse attributed to increased cost estimates to complete its U.S. nuclear projects, including Plant Vogtle Units 3 and 4. Toshiba also warned that it will likely be in a negative equity position as a result of the charges. At the same time, Toshiba reaffirmed its commitment to its U.S. nuclear projects with implementation of management changes and increased oversight. An inability or failure by the Contractor to perform its obligations under the Vogtle 3 and 4 Agreement could have a material impact on the construction of Plant Vogtle Units 3 and 4.

Under the terms of the Vogtle 3 and 4 Agreement, the Contractor does not have a right to terminate the Vogtle 3 and 4 Agreement for convenience. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. In the event of an abandonment of work by the Contractor, the maximum liability of the Contractor under the Vogtle 3 and 4 Agreement is increased significantly, but remains subject to limitations. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for convenience, provided that the Vogtle Owners will be required to pay certain termination costs.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved an NCCR tariff of $368 million for 2014, as well as increases to the NCCR tariff of approximately $27 million and $19 million effective January 1, 2015 and 2016, respectively.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. In accordance with the 2009 certification order, the Company requested amendments to the Plant Vogtle Units 3 and 4 certificate in both the February 2013 (eighth VCM) and February 2015 (twelfth VCM) filings, when projected construction capital costs to be borne by the Company increased by 5% above the certified costs and estimated in-service dates were extended. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between the Company and the Georgia PSC Staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and the Company. In April 2015, the Georgia PSC recognized that the certified cost and the 2013 Stipulation did not constitute a cost recovery cap and deemed the amendment requested in the February 2015 filing unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation.

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including litigation that was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation). Effective December 31, 2015, the Company, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will commence if the nuclear fuel loading date for each unit does not occur by December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4; and (v) provide that the Company, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million, of which approximately $263 million had been paid as of December 31, 2016. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs are reflected in the Company's current in-service forecast of $5.440 billion. Further, as part of the settlement and Westinghouse's acquisition of WECTEC: (i) Westinghouse engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor and (ii) the Vogtle Owners, Chicago Bridge & Iron Co, N.V., and The Shaw Group Inc. entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving the following prudence matters: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report will be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement is reasonable and prudent and none of the amounts paid or to be paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) financing costs on verified and approved capital costs will be deemed prudent provided they are incurred prior to December 31, 2019 and December 31, 2020 for Plant Vogtle Units 3 and 4, respectively; and (iv) (a) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above the Company's current forecast of $5.440 billion, (b) capital costs incurred up to the Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (c) the Company would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent. Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating the NCCR tariff will remain at $4.418 billion. Construction capital costs above $4.418 billion will accrue AFUDC through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be the Company's average cost of long-term debt. If the Georgia PSC adjusts the Company's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be the Company's average cost of long-term debt.

Under the terms of the Vogtle Cost Settlement Agreement, Plant Vogtle Units 3 and 4 will be placed into retail rate base on December 31, 2020 or when placed in service, whichever is later. The Georgia PSC will determine for retail ratemaking purposes the process of transitioning Plant Vogtle Units 3 and 4 from a construction project to an operating plant no later than the Company's base rate case required to be filed by July 1, 2019.

The Georgia PSC has approved fifteen VCM reports covering the periods through June 30, 2016, including construction capital costs incurred, which through that date totaled $3.7 billion. The Company expects to file the sixteenth VCM report, covering the period from July 1 through December 31, 2016, requesting approval of $222 million of construction capital costs incurred during that period, with the Georgia PSC by February 28, 2017. The Company's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.9 billion as of December 31, 2016, and the Company had incurred $1.3 billion in financing costs through December 31, 2016.

As of December 31, 2016, the Company had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between the Company and the DOE and a multi-advance credit facility among the Company, the DOE, and the FFB. See Note 6 under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, and mandatory prepayment events.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise as construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

In addition to Toshiba's reaffirmation of its commitment, the Contractor provided the Company with revised forecasted in-service dates of December 2019 and September 2020 for Plant Vogtle Units 3 and 4, respectively. The Company is currently reviewing a preliminary summary schedule supporting these dates that ultimately must be reconciled to a detailed integrated project schedule. As construction continues, the risk remains that challenges with Contractor performance including labor productivity, fabrication, delivery, assembly, and installation of plant systems, structures, and components, or other issues could arise and may further impact project schedule and cost. The Company expects the Contractor to employ mitigation efforts and believes the Contractor is responsible for any related costs under the Vogtle 3 and 4 Agreement. The Company estimates its financing costs for Plant Vogtle Units 3 and 4 to be approximately $30 million per month, with total construction period financing costs of approximately $2.5 billion. Additionally, the Company estimates its owner's costs to be approximately $6 million per month, net of delay liquidated damages.

The revised forecasted in-service dates are within the timeframe contemplated in the Vogtle Cost Settlement Agreement and would enable both units to qualify for production tax credits the IRS has allocated to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021. The net present value of the production tax credits is estimated at approximately $400 million per unit.

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

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

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a ROE. The Company's share of purchased power totaled $57 million in 2016, $78 million in 2015, and $84 million in 2014 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method. See Note 7 under "Guarantees" for additional information.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC, which is the operator of the plant. On August 31, 2016, the Company sold its 33% ownership interest in the Intercession City combustion turbine unit to Duke Energy Florida, LLC.

At December 31, 2016, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership	Plant in Service	Accumulated Depreciation	CWIP
			(in millions)	
Plant Vogtle (nuclear)				
Units 1 and 2	45.7%	$ 3,545	$ 2,111	$ 74
Plant Hatch (nuclear)	50.1	1,297	585	81
Plant Wansley (coal)	53.5	1,046	308	12
Plant Scherer (coal)				
Units 1 and 2	8.4	258	90	3
Unit 3	75.0	1,203	458	23
Rocky Mountain (pumped storage)	25.4	181	129	—

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

The Company also owns 45.7% of Plant Vogtle Units 3 and 4, which are currently under construction and had a CWIP balance of approximately $3.9 billion as of December 31, 2016. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2016	2015	2014
		(in millions)	
Federal –			
Current	$ 391	$ 515	$ 295
Deferred	319	176	366
	710	691	661
State –			
Current	6	81	82
Deferred	64	(3)	(14)
	70	78	68
Total	$ 780	$ 769	$ 729

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

	2016	2015
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	$ 5,266	$ 4,909
Property basis differences	957	1,003
Employee benefit obligations	428	310
Premium on reacquired debt	56	61
Regulatory assets –		
Storm damage reserves	83	37
Employee benefit obligations	546	528
Asset retirement obligations	726	545
Retired assets	55	58
Asset retirement obligations	182	161
Other	83	92
Total	8,382	7,704
Deferred tax assets –		
Federal effect of state deferred taxes	173	150
Employee benefit obligations	661	642
Other property basis differences	105	88
Other deferred costs	100	83
State investment tax credit carryforward	201	216
Federal tax credit carryforward	84	3
Unbilled fuel revenue	47	47
Regulatory liabilities associated with asset retirement obligations	33	60
Asset retirement obligations	908	706
Other	70	82
Total	2,382	2,077
Accumulated deferred income taxes	$ 6,000	$ 5,627

The application of bonus depreciation provisions in current tax law significantly increased deferred tax liabilities related to accelerated depreciation in 2016 and 2015.

At December 31, 2016, tax-related regulatory assets to be recovered from customers were $681 million. These assets are primarily attributable to tax benefits flowed through to customers in prior years and deferred taxes previously recognized at rates lower than the current enacted tax law.

At December 31, 2016, tax-related regulatory liabilities to be credited to customers were $121 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law.

In accordance with regulatory requirements, utilized federal ITCs are deferred and amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $10 million in each of 2016, 2015, and 2014. State investment tax credits are recognized in the period in which the credits are generated and totaled $42 million in 2016, $33 million in 2015, and $34 million in 2014. At December 31, 2016, the Company had $83 million in federal ITC carryforwards that will expire by 2036 and $201 million in state ITC carryforwards that will expire between 2019 and 2027.

Effective Tax Rate

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

	2016	2015	2014
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.1**	2.5	2.2
Non-deductible book depreciation	**0.8**	1.2	1.3
AFUDC equity	**(0.8)**	(0.7)	(0.8)
Other	**(0.4)**	(0.4)	(0.7)
Effective income tax rate	**36.7%**	37.6%	37.0%

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

Unrecognized Tax Benefits

The Company had no unrecognized tax benefits as of December 31, 2016 and no material changes in unrecognized tax benefits for any year presented.

The Company classifies interest on tax uncertainties as interest expense; however, the Company did not have any accrued interest or penalties for unrecognized tax benefits for any year presented.

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

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

6. FINANCING

Securities Due Within One Year

A summary of scheduled maturities of long-term debt due within one year at December 31 was as follows:

		2016		2015
		(in millions)		
Senior notes	**$**	**450**	$	700
Pollution control revenue bonds		**—**		4
Capital leases		**10**		8
Total	**$**	**460**	$	712

Maturities through 2021 applicable to total long-term debt are as follows: $460 million in 2017; $762 million in 2018; $513 million in 2019; $57 million in 2020; and $376 million in 2021.

Senior Notes

In March 2016, the Company issued $325 million aggregate principal amount of Series 2016A 3.25% Senior Notes due April 1, 2026 and $325 million aggregate principal amount of Series 2016B 2.40% Senior Notes due April 1, 2021. An amount equal to the proceeds from the Series 2016A 3.25% Senior Notes due April 1, 2026 is being allocated to eligible green expenditures, including financing of or investments in solar generating facilities or electric vehicle charging infrastructure, or payments under PPAs served by solar or wind generating facilities. The proceeds from the Series 2016B 2.40% Senior Notes due April 1, 2021 were used to repay at maturity $250 million aggregate principal amount of the Company's Series 2013B Floating Rate Senior Notes due March 15, 2016, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2016 and 2015, the Company had $6.2 billion and $6.3 billion of senior notes outstanding, respectively, which included senior notes due within one year. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $2.8 billion and $2.4 billion at December 31, 2016 and 2015, respectively. As of December 31, 2016, the Company's secured debt included borrowings of $2.6 billion guaranteed by the DOE and capital lease obligations of $169 million. As of December 31, 2015, the Company's secured debt included borrowings of $2.2 billion guaranteed by the DOE and capital lease obligations of $183 million. See Note 7 and "DOE Loan Guarantee Borrowings" herein for additional information.

Pollution Control Revenue Bonds

Pollution control revenue bond 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 bond obligations outstanding at both December 31, 2016 and 2015 was $1.8 billion.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) in February 2014, under which the DOE agreed to guarantee the obligations of the Company under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, the Company, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which the Company may make term loan borrowings through the FFB.

Proceeds of advances made under the FFB Credit Facility are used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion.

All borrowings under the FFB Credit Facility are full recourse to the Company, and the Company is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. The Company's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on the Company's ability to grant liens on other property.

Advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375%.

In connection with its entry into the agreements with the DOE and the FFB, the Company incurred issuance costs of approximately $66 million, which are being amortized over the life of the borrowings under the FFB Credit Facility.

In June and December 2016, the Company made borrowings under the FFB Credit Facility in an aggregate principal amount of $300 million and $125 million, respectively. The interest rate applicable to the $300 million principal amount is 2.571% and the interest rate applicable to the $125 million principal amount is 3.142%, both for an interest period that extends to the final maturity date of February 20, 2044.

At December 31, 2016 and 2015, the Company had $2.6 billion and $2.2 billion of borrowings outstanding under the FFB Credit Facility, respectively. Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Under the Loan Guarantee Agreement, the Company is subject to customary borrower affirmative and negative covenants and events of default. In addition, the Company is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and the Company will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Among other things, these mandatory prepayment events include (i) the termination of the Vogtle 3 and 4 Agreement; (ii) cancellation of Plant Vogtle Units 3 and 4 by the Georgia PSC, or by the Company if authorized by the Georgia PSC; and (iii) cost disallowances by the Georgia PSC that could have a material adverse effect on completion of Plant Vogtle Units 3 and 4 or the Company's ability to repay the outstanding borrowings under the FFB Credit Facility. Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. The Company also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Promissory Note, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume the Company's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of the Company's ownership interest in Plant Vogtle Units 3 and 4.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2016 and 2015, the Company had a capital lease asset for its corporate headquarters building of $61 million, with accumulated depreciation at December 31, 2016 and 2015 of $33 million and $26 million, respectively. At December 31, 2016 and 2015, the capitalized lease obligation was $28 million and $35 million, respectively, with an annual interest rate of 7.9% for both years. For ratemaking purposes, the Georgia PSC has allowed the lease payments in cost of service with no return on the capital lease asset. The difference between the depreciation and the lease payments allowed for ratemaking purposes is recovered as operating expenses as ordered by the Georgia PSC. The annual operating expense incurred for this capital lease was not material for any year presented.

At December 31, 2016 and 2015, the Company had capital lease assets related to two PPAs with Southern Power of $149 million, with accumulated amortization at December 31, 2016 and 2015 of $19 million and $10 million, respectively. At December 31, 2016 and 2015, the related capitalized lease obligations were $141 million and $148 million, respectively. The annual interest rates range from 10% to 11% for these two capital lease PPAs. For ratemaking purposes, the Georgia PSC has included the capital lease asset amortization in cost of service and the interest in the Company's cost of debt. See Note 1 under "Affiliate Transactions" and Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Assets Subject to Lien

See "DOE Loan Guarantee Borrowings" above for information regarding certain borrowings of the Company that are secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4.

See "Capital Leases" above for information regarding certain assets held under capital leases.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. The outstanding series of the Class A preferred stock is subject to redemption at the option of the Company at any time at a redemption price equal to 100% of the par value. In addition, on or after October 1, 2017, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the par value. With respect to any redemption of the preference stock prior to October 1, 2017, the redemption price includes a make-whole premium based on the present value of the liquidation amount and future dividends through the first par redemption date.

Dividend Restrictions

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

Bank Credit Arrangements

At December 31, 2016, the Company had a $1.75 billion committed credit arrangement with banks, of which $1.73 billion was unused. This credit arrangement expires in 2020.

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

This bank credit arrangement contains a covenant that limits the Company's debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes certain hybrid securities. At December 31, 2016, the Company was in compliance with the debt limit covenant.

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

A portion of the $1.73 billion unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and its commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was $868 million. In addition, at December 31, 2016, the Company had $250 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangement described above. Commercial paper is included in notes payable in the balance sheets.

Details of commercial paper borrowings outstanding were as follows:

	Commercial Paper at the End of the Period	
	Amount Outstanding	**Weighted Average Interest Rate**
	(in millions)	
December 31, 2016	**$ 392**	**1.1%**
December 31, 2015	$ 158	0.6%

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2016, 2015, and 2014, the Company incurred fuel expense of $1.8 billion, $2.0 billion, and $2.5 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

The Company has commitments regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of MEAG Power's Plant Vogtle Units 1 and 2 allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $11 million, $10 million, and $19 million in 2016, 2015, and 2014, respectively.

The Company has also entered into various long-term PPAs, some of which are accounted for as capital or operating leases. Total capacity expense under PPAs accounted for as operating leases was $217 million, $203 million, and $167 million for 2016, 2015, and 2014, respectively. Estimated total long-term obligations at December 31, 2016 were as follows:

	Affiliate Capital Leases	Affiliate Operating Leases	Non-Affiliate Operating Leases[c]	Vogtle Units 1 and 2 Capacity Payments	Total
			(in millions)		
2017	$ 22	$ 72	$ 123	$ 8	$ 225
2018	22	63	126	7	218
2019	23	64	127	6	220
2020	23	65	123	5	216
2021	24	66	124	5	219
2022 and thereafter	204	479	882	43	1,608
Total	$ 318	$ 809	$ 1,505	$ 74	$ 2,706
Less: amounts representing executory costs[a]	48				
Net minimum lease payments	270				
Less: amounts representing interest[b]	128				
Present value of net minimum lease payments	$ 142				

(a) Executory costs such as taxes, maintenance, and insurance (including the estimated profit thereon) are estimated and included in total minimum lease payments.

(b) Calculated using an adjusted incremental borrowing rate to reduce the present value of the net minimum lease payments to fair value.

(c) A total of $197 million of biomass PPAs included under the non-affiliate operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation. Subsequent to December 31, 2016, the specified contract dates for commercial operation were extended from 2017 to 2019 and may change further as a result of regulatory action.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the PPA operating leases discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $28 million for 2016, $29 million for 2015, and $28 million for 2014. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2016, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
		(in millions)	
2017	$ 12	$ 7	$ 19
2018	6	7	13
2019	3	6	9
2020	3	6	9
2021	2	6	8
2022 and thereafter	2	13	15
Total	$ 28	$ 45	$ 73

Railcar minimum lease payments are disclosed at 100% of railcar lease obligations; however, a portion of these obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the railcar leases are recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

In addition to the above rental commitments, the Company has obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $32 million. At the termination of the leases, the lessee may either renew the lease, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

Alabama Power has guaranteed the obligations of SEGCO for $25 million of pollution control revenue bonds issued in 2001, which mature in June 2019, and also $100 million of senior notes issued in 2013, which mature in December 2018. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of SEGCO's stock if Alabama Power is called upon to make such payment under its guarantee. See Note 4 for additional information.

In addition, in 2013, the Company entered into an agreement that requires the Company to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years. The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2018. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million.

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to railcar leases.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2016, there were 990 current and former employees participating in the stock option and performance share unit programs.

Stock Options

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

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

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

The total intrinsic value of options exercised during the years ended December 31, 2016, 2015, and 2014 was $18 million, $9 million, and $19 million, respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $7 million, $4 million, and $7 million for the years ended December 31, 2016, 2015, and 2014, respectively. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2016, the aggregate intrinsic value for the options outstanding and options exercisable was $46 million and $41 million, respectively.

Performance Share Units

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

The performance goal for all performance share units issued from 2010 through 2014 was based on the total shareholder return (TSR) for Southern Company common stock during the three-year performance period as compared to a group of industry peers. For these performance share units, at the end of three years, active employees receive shares based on Southern Company's performance while retired employees receive a pro rata number of shares based on the actual months of service during the performance period prior to retirement. The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement.

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

For the years ended December 31, 2016, 2015, and 2014, employees of the Company were granted performance share units of 261,434, 236,804, and 176,224, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2016, 2015, and 2014, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $45.17, $46.41, and $37.54, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2016 and 2015 was $48.84 and $47.78, respectively.

For the years ended December 31, 2016, 2015, and 2014, total compensation cost for performance share units recognized in income was $15 million, $15 million, and $6 million, respectively, with the related tax benefit also recognized in income of $6 million, $6 million, and $2 million, respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2016, $4 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 22 months.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests in all licensed reactors, is $247 million per incident, but not more than an aggregate of $37 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. In April 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases limits based on the projected full cost of replacement power, subject to ownership limitations, and has elected a 12-week deductible waiting period for each facility.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Vogtle Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for the Company as of December 31, 2016 under the NEIL policies would be $82 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

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

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

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

As of December 31, 2016, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2016:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 44	$ —	$ 44
Interest rate derivatives	—	2	—	2
Nuclear decommissioning trusts:(*)				
Domestic equity	204	1	—	205
Foreign equity	—	121	—	121
U.S. Treasury and government agency securities	—	71	—	71
Municipal bonds	—	73	—	73
Corporate bonds	—	164	—	164
Mortgage and asset backed securities	—	164	—	164
Other	11	5	—	16
Total	$ 215	$ 645	$ —	$ 860
Liabilities:				
Energy-related derivatives	$ —	$ 8	$ —	$ 8
Interest rate derivatives	—	3	—	3
Total	$ —	$ 11	$ —	$ 11

(*) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

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

	Fair Value Measurements Using			
As of December 31, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 2	$ —	$ 2
Interest rate derivatives	—	5	—	5
Nuclear decommissioning trusts:(*)				
Domestic equity	182	1	—	183
Foreign equity	—	113	—	113
U.S. Treasury and government agency securities	—	125	—	125
Municipal bonds	—	64	—	64
Corporate bonds	—	143	—	143
Mortgage and asset backed securities	—	127	—	127
Other	16	4	—	20
Cash equivalents	63	—	—	63
Total	$ 261	$ 584	$ —	$ 845
Liabilities:				
Energy-related derivatives	$ —	$ 15	$ —	$ 15
Interest rate derivatives	—	6	—	6
Total	$ —	$ 21	$ —	$ 21

(*) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

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 reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2016 and 2015, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt, including securities due within one year:		
2016	**$ 10,516**	**$ 11,034**
2015	$ 10,145	$ 10,480

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

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 10 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages a fuel-hedging program through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. At December 31, 2016 and 2015, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Through December 31, 2015, the Company's fuel-hedging program had a time horizon up to 24 months. Effective January 1, 2016, the Georgia PSC approved changes to the Company's hedging program allowing it to use an array of derivative instruments within a 48-month time horizon.

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

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

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

At December 31, 2016, the net volume of energy-related derivative contracts for natural gas positions totaled 155 million mmBtu, all of which expire by 2020, which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 3 million mmBtu for the Company.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. At December 31, 2016, there were no cash flow hedges outstanding. Derivatives related to fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains and losses and the hedged items' fair value gains and losses attributable to interest rate risk are both recorded directly to earnings, providing an offset, with any differences representing ineffectiveness.

At December 31, 2016, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2016
	(in millions)				*(in millions)*
Fair Value Hedges of Existing Debt					
	$ 250	5.40%	3-month LIBOR + 4.02%	June 2018	$ —
	500	1.95%	3-month LIBOR + 0.76%	December 2018	(2)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	1
Total	$ 950				$ (1)

The estimated pre-tax gains (losses) that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2017 total $4 million. Deferred gains and losses related to interest rate derivative settlements of cash flow hedges are expected to be amortized into earnings through 2037.

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. At December 31, 2016, fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties. At December 31, 2015, the fair value amounts of derivative instruments were presented gross on the balance sheets.

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

	2016		2015	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	Assets	Liabilities
		(in millions)		
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 30**	**$ 1**	$ 2	$ 12
Other deferred charges and assets/Other deferred credits and liabilities	**14**	**7**	—	3
Total derivatives designated as hedging instruments for regulatory purposes	**$ 44**	**$ 8**	$ 2	$ 15
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Interest rate derivatives:				
Other current assets/Other current liabilities	**$ 2**	**$ —**	$ 5	$ —
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**3**	—	6
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**$ 2**	**$ 3**	$ 5	$ 6
Gross amounts recognized	**$ 46**	**$ 11**	$ 7	$ 21
Gross amounts offset	**$ (8)**	**$ (8)**	$ (6)	$ (6)
Net amounts recognized in the Balance Sheets(*)	**$ 38**	**$ 3**	$ 1	$ 15

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

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

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

	Unrealized Losses			**Unrealized Gains**		
Derivative Category	**Balance Sheet Location**	**2016**	2015	**Balance Sheet Location**	**2016**	2015
		(in millions)			*(in millions)*	
Energy-related derivatives:(*)	Other regulatory assets, current	**$ —**	$ (12)	Other regulatory liabilities, current	**$ 29**	$ 2
	Other regulatory assets, deferred	**—**	(3)	Other deferred credits and liabilities	**7**	—
Total energy-related derivative gains (losses)		**$ —**	$ (15)		**$ 36**	$ 2

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

For the years ended December 31, 2016, 2015, and 2014, 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	**2016**	2015	2014	**Statements of Income Location**	**2016**	2015	2014
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ —**	$ (15)	$ (8)	Interest expense, net of amounts capitalized	**$ (4)**	$ (3)	$ (3)

For the years ended December 31, 2016 and 2015, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on the statements of income were immaterial on a gross basis for the Company. Furthermore, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the Company's statements of income were offset by changes to the carrying value of long-term debt. The gains and losses related to interest rate derivative settlements of fair value hedges are recorded directly to earnings.

There was no material ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was immaterial for all years presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2016, the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2016, the fair value of derivative liabilities with contingent features, including certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade because of joint and several liability features underlying these derivatives, was immaterial.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2016 and 2015 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2016	**$ 1,872**	**$ 509**	**$ 269**
June 2016	**2,051**	**656**	**349**
September 2016	**2,698**	**1,054**	**599**
December 2016	**1,762**	**258**	**113**
March 2015	$ 1,978	$ 454	$ 236
June 2015	2,016	554	277
September 2015	2,691	964	551
December 2015	1,641	376	196

In accordance with the adoption of ASU 2016-09 (see Note 1 under "Recently Issued Accounting Standards"), previously reported amounts for income tax expense were reduced by $1 million in the third quarter 2016, $2 million in the second quarter 2016, and $1 million in the first quarter 2016.

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

SELECTED FINANCIAL AND OPERATING DATA 2012-2016
Georgia Power Company 2016 Annual Report

		2016		2015		2014		2013		2012
Operating Revenues (in millions)	**$**	**8,383**	$	8,326	$	8,988	$	8,274	$	7,998
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$**	**1,330**	$	1,260	$	1,225	$	1,174	$	1,168
Cash Dividends on Common Stock (in millions)	**$**	**1,305**	$	1,034	$	954	$	907	$	983
Return on Average Common Equity (percent)		**12.05**		11.92		12.24		12.45		12.76
Total Assets (in millions)[(a)(b)]	**$**	**34,835**	$	32,865	$	30,872	$	28,776	$	28,618
Gross Property Additions (in millions)	**$**	**2,314**	$	2,332	$	2,146	$	1,906	$	1,838
Capitalization (in millions):										
Common stock equity	**$**	**11,356**	$	10,719	$	10,421	$	9,591	$	9,273
Preferred and preference stock		**266**		266		266		266		266
Long-term debt[(a)]		**10,225**		9,616		8,563		8,571		7,928
Total (excluding amounts due within one year)	**$**	**21,847**	$	20,601	$	19,250	$	18,428	$	17,467
Capitalization Ratios (percent):										
Common stock equity		**52.0**		52.0		54.1		52.0		53.1
Preferred and preference stock		**1.2**		1.3		1.4		1.4		1.5
Long-term debt[(a)]		**46.8**		46.7		44.5		46.6		45.4
Total (excluding amounts due within one year)		**100.0**		100.0		100.0		100.0		100.0
Customers (year-end):										
Residential		**2,155,945**		2,127,658		2,102,673		2,080,358		2,062,040
Commercial[(c)]		**305,488**		302,891		300,186		297,493		295,523
Industrial[(c)]		**10,537**		10,429		10,192		10,063		10,017
Other		**9,585**		9,261		9,003		8,623		7,724
Total		**2,481,555**		2,450,239		2,422,054		2,396,537		2,375,304
Employees (year-end)		**7,527**		7,989		7,909		7,886		8,094

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $124 million, $62 million, and $67 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $34 million, $68 million, and $117 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(c) A reclassification of customers from commercial to industrial is reflected for years 2012-2015 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

SELECTED FINANCIAL AND OPERATING DATA 2012-2016 (continued)
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	2016	2015	2014	2013	2012
Operating Revenues (in millions):					
Residential	**$ 3,318**	$ 3,240	$ 3,350	$ 3,058	$ 2,986
Commercial	**3,077**	3,094	3,271	3,077	2,965
Industrial	**1,291**	1,305	1,525	1,391	1,322
Other	**86**	88	94	94	89
Total retail	**7,772**	7,727	8,240	7,620	7,362
Wholesale — non-affiliates	**175**	215	335	281	281
Wholesale — affiliates	**42**	20	42	20	20
Total revenues from sales of electricity	**7,989**	7,962	8,617	7,921	7,663
Other revenues	**394**	364	371	353	335
Total	**$ 8,383**	$ 8,326	$ 8,988	$ 8,274	$ 7,998
Kilowatt-Hour Sales (in millions):					
Residential	**27,585**	26,649	27,132	25,479	25,742
Commercial	**32,932**	32,719	32,426	31,984	32,270
Industrial	**23,746**	23,805	23,549	23,087	23,089
Other	**610**	632	633	630	641
Total retail	**84,873**	83,805	83,740	81,180	81,742
Wholesale — non-affiliates	**3,415**	3,501	4,323	3,029	2,934
Wholesale — affiliates	**1,398**	552	1,117	496	600
Total	**89,686**	87,858	89,180	84,705	85,276
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.03**	12.16	12.35	12.00	11.60
Commercial	**9.34**	9.46	10.09	9.62	9.19
Industrial	**5.44**	5.48	6.48	6.03	5.73
Total retail	**9.16**	9.22	9.84	9.39	9.01
Wholesale	**4.51**	5.80	6.93	8.54	8.52
Total sales	**8.91**	9.06	9.66	9.35	8.99
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,864**	12,582	12,969	12,293	12,509
Residential Average Annual Revenue Per Customer	**$ 1,557**	$ 1,529	$ 1,605	$ 1,475	$ 1,451
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,274**	15,455	17,593	17,586	17,984
Maximum Peak-Hour Demand (megawatts):					
Winter	**14,527**	15,735	16,308	12,767	14,104
Summer	**16,244**	16,104	15,777	15,228	16,440
Annual Load Factor (percent)	**61.9**	61.9	61.2	63.5	59.1
Plant Availability (percent):					
Fossil-steam	**87.4**	85.6	86.3	87.1	90.3
Nuclear	**95.6**	94.1	90.8	91.8	94.1
Source of Energy Supply (percent):					
Coal	**26.4**	24.5	30.9	26.4	26.6
Nuclear	**17.6**	17.6	16.7	17.7	18.3
Hydro	**1.1**	1.6	1.3	2.0	0.7
Oil and gas	**28.2**	28.3	26.3	29.6	22.0
Purchased power —					
From non-affiliates	**6.7**	5.0	3.8	3.3	6.8
From affiliates	**20.0**	23.0	21.0	21.0	25.6
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Georgia Power Company 2016 Annual Report

Directors

W. Paul Bowers
Chairman, President, and Chief Executive Officer
Georgia Power Company

Robert L. Brown, Jr. (Retiring effective 5/17/2017)
President and Chief Executive Officer
R. L. Brown & Associates, Inc.

Shantella E. Cooper (Elected effective 4/1/2017)
Chief Transformation Officer
WestRock Company

Anna R. Cablik (Retiring effective 5/17/2017)
Owner and President
Anatek, Inc. and Anasteel & Supply Company, LLC

Lawrence L. Gellerstedt III (Elected effective 4/1/2017)
President and Chief Executive Officer
Cousins Properties Incorporated

Stephen S. Green
President and Chief Executive Officer
Stephen Green Properties, Inc.

Douglas J. Hertz (Elected effective 1/1/2017)
President and Chief Executive Officer
United Distributors, Inc.

Kessel D. Stelling, Jr.
Chairman, President, and Chief Executive Officer
Synovus Financial Corporation

Jimmy C. Tallent
Chairman and Chief Executive Officer
United Community Banks, Inc. and United Community Bank

Charles K. Tarbutton
Treasurer and Director
B-H Transfer Co.

Beverly Daniel Tatum
President Emerita
Spelman College

Clyde C. Tuggle
Senior Vice President and Chief Public Affairs and Communications Officer
The Coca-Cola Company

Richard W. Ussery (Retiring effective 5/17/2017)
Retired Chairman and Chief Executive Officer
Total System Services, Inc.

Officers

W. Paul Bowers
Chairman, President, and Chief Executive Officer
Georgia Power Company

W. Craig Barrs (Retired effective 3/31/2017)
Executive Vice President
Customer Service and Operations

Pedro P. Cherry (Elected effective 3/31/2017)
Executive Vice President
Customer Service and Operations

Christopher P. Cummiskey
Executive Vice President
External Affairs

W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer

Michael K. Anderson
Senior Vice President
Community and Corporate Relations

Kenneth E. Coleman
Senior Vice President
Marketing

Meredith M. Lackey (Elected effective 11/1/2016)
Senior Vice President, General Counsel, and Corporate Secretary

Theodore J. McCullough (Elected effective 7/30/2016)
Senior Vice President and
Senior Production Officer
Generation

John L. Pemberton (Resigned effective 7/29/2016)
Senior Vice President and
Senior Production Officer
Generation

Bentina C. Terry (Elected effective 3/31/2017)
Senior Vice President
Metro Atlanta Region

Latanza W. Adjei
Vice President
Sales

Mark S. Berry
Vice President
Environmental Affairs

DIRECTORS AND OFFICERS
Georgia Power Company 2016 Annual Report

Melissa K. Caen
Assistant Secretary

Moanica M. Caston (Retired effective 12/9/2016)
Vice President
Diversity and Inclusion

Lenn H. Chandler
Vice President
Northeast Region

P. Mike Clanton (Retired effective 1/1/2017)
Vice President
Land

Jason T. Cuevas
Vice President
West Region

John A. D'Andrea (Elected effective 1/1/2017)
Vice President
Governmental Affairs

Kristi L. Dow
Assistant Secretary

J. Truitt Eavenson
Vice President
Coastal Region

Sloane N. Evans
Vice President
Human Resources

Fran G. Forehand
Vice President
East Region

Jeff G. Franklin
Vice President
Supply Chain

Glen R. Grizzle
Vice President
Corporate Services

Valerie Hendrickson
Vice President
Corporate Communications

Cathy P. Hill
Vice President
Land

Anne H. Kaiser
Vice President
Community and Economic Development

Stacy R. Kilcoyne (Resigned effective 3/2/2017)
Vice President
Human Resource Services

Kyle C. Leach (Elected effective 1/1/2017)
Vice President
Regulatory Affairs

Danny W. Lindsey
Vice President
Transmission

Jason E. Manley
Vice President
South Region

William N. (Norrie) McKenzie
Vice President
Renewable Development

David L. McKinney
Vice President
Nuclear Development

Todd A. Perkins
Assistant Treasurer

David P. Poroch
Vice President and Comptroller

Gregory N. Roberts
Vice President
Pricing and Planning

Louise L. Scott
Vice President
Customer Services

Ronald Shipman
Vice President
Central Region

Leslie R. Sibert
Vice President
Distribution

Michael J. Sullivan (Resigned effective 11/8/2016)
Vice President
Information Technology

H. Murry Weaver II
Vice President
Northwest Region

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

Profile
The Company operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast. The Company provides electric service to approximately 2.48 million customers within its service territory. In 2016, retail energy sales accounted for approximately 95% of the Company's total sales of 89.7 billion kilowatt-hours.

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

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40th Floor
New York, NY 10017
(917) 260-1534

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St. Paul, MN 55154-0856
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www.shareowneronline.com

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

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

Quarter	2016	2015
	(in thousands)	
First	$326,269	$258,570
Second	326,269	258,570
Third	326,269	258,570
Fourth	326,269	258,570

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

Form 10-K
A copy of the Form 10-K as filed with the Securities and Exchange Commission will be provided without charge upon written request to the office of the Corporate Secretary. Requests for copies should be directed to the Corporate Secretary, 241 Ralph McGill Boulevard, N.E., Atlanta, GA 30308-3374. For additional information, contact the office of the Corporate Secretary at (404) 506-7455.

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

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