ALABAMA POWER COMPANY

2017 ANNUAL REPORT

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Alabama Power Company 2017 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017.

Mark A. Crosswhite
Chairman, President, and Chief Executive Officer

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer

February 20, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Alabama Power Company

Opinion on the Financial Statements

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016, 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, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages 31 to 76) present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting 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.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Deloitte & Touche LLP

Birmingham, Alabama
February 20, 2018

We have served as the Company's auditor since 2002.

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
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
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NDR	Natural Disaster Reserve
NO_X	Nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
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
Rate CNP	Rate Certificated New Plant
Rate CNP Compliance	Rate Certificated New Plant Compliance
Rate CNP PPA	Rate Certificated New Plant Power Purchase Agreement
Rate ECR	Rate Energy Cost Recovery
Rate NDR	Rate Natural Disaster Reserve
Rate RSE	Rate Stabilization and Equalization plan
ROE	Return on equity
S&P	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
SO_2	Sulfur dioxide
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas and its subsidiaries

DEFINITIONS
(continued)

Term	Meaning
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
Tax Reform Legislation	The Tax Cuts and Jobs Act, which was signed into law on December 22, 2017 and became effective on January 1, 2018
traditional electric operating companies	Alabama Power Company, Georgia Power, Gulf Power, and Mississippi Power

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales and customers, 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. 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.

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

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

Earnings

The Company's 2017 net income after dividends on preferred and preference stock was $848 million, representing a $26 million, or 3.2%, increase over the previous year. The increase was primarily due to an increase in rates under Rate RSE effective in January 2017 and the impact of a Rate RSE refund recorded in 2016. These increases to income were partially offset by a decrease in retail revenues associated with milder weather, lower customer usage, and an increase in non-fuel operations and maintenance expenses in 2017 as compared to 2016. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate RSE" herein for additional information.

The Company's 2016 net income after dividends on preferred and preference stock was $822 million, representing a $37 million, or 4.7%, increase over the previous year. The increase was due primarily to an increase in retail revenues under Rate CNP Compliance, an increase in weather-related revenues, and a decrease in operations and maintenance expenses not related to fuel or Rate CNP Compliance. These increases to income were partially offset by an accrual for a Rate RSE refund, a decrease in AFUDC equity, and an increase in depreciation.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2017	**2017**	2016
		(in millions)	
Operating revenues	**$ 6,039**	**$ 150**	$ 121
Fuel	**1,225**	**(72)**	(45)
Purchased power	**328**	**(6)**	(17)
Other operations and maintenance	**1,652**	**142**	9
Depreciation and amortization	**736**	**33**	60
Taxes other than income taxes	**384**	**4**	12
Total operating expenses	**4,325**	**101**	19
Operating income	**1,714**	**49**	102
Allowance for equity funds used during construction	**39**	**11**	(32)
Interest expense, net of amounts capitalized	**305**	**3**	28
Other income (expense), net	**(14)**	**7**	11
Income taxes	**568**	**37**	25
Net income	**866**	**27**	28
Dividends on preferred and preference stock	**18**	**1**	(9)
Net income after dividends on preferred and preference stock	**$ 848**	**$ 26**	$ 37

Operating Revenues

Operating revenues for 2017 were $6.0 billion, reflecting a $150 million increase from 2016. Details of operating revenues were as follows:

	Amount	
	2017	2016
	(in millions)	
Retail — prior year	**$ 5,322**	$ 5,234
Estimated change resulting from —		
Rates and pricing	**362**	147
Sales decline	**(44)**	(20)
Weather	**(89)**	31
Fuel and other cost recovery	**(93)**	(70)
Retail — current year	**5,458**	5,322
Wholesale revenues —		
Non-affiliates	**276**	283
Affiliates	**97**	69
Total wholesale revenues	**373**	352
Other operating revenues	**208**	215
Total operating revenues	**$ 6,039**	$ 5,889
Percent change	**2.6%**	2.1%

Retail revenues in 2017 were $5.5 billion. These revenues increased $136 million, or 2.6%, in 2017 and $88 million, or 1.7%, in 2016, each as compared to the prior year. The increase in 2017 was primarily due to an increase in rates under Rate RSE effective in January 2017, partially offset by a decrease in fuel revenues and milder weather in the first and third quarters 2017 as compared to the corresponding periods in 2016. The increase in 2016 was due to an increase in revenues under Rate CNP Compliance as a result of increased net investments, partially offset by a decrease in fuel revenues and an accrual for a Rate RSE refund. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information. See "Energy Sales" herein for a discussion of changes in the volume of energy sold, including changes related to sales decline and weather.

Fuel rates billed to customers are designed to fully recover fluctuating fuel and purchased power costs over a period of time. Fuel revenues generally have no effect on net income because they represent the recording of revenues to offset fuel and purchased power expenses. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate ECR" for additional information.

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

	2017	2016	2015
		(in millions)	
Capacity and other	**$ 154**	$ 154	$ 140
Energy	**122**	129	101
Total non-affiliated	**$ 276**	$ 283	$ 241

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 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 affect net income. Short-term opportunity energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

In 2017, wholesale revenues from sales to non-affiliates decreased $7 million, or 2.5%, as compared to the prior year. In 2016, wholesale revenues from sales to non-affiliates increased $42 million, or 17.4%, as compared to the prior year primarily due to a $28 million increase in revenues from energy sales and a $14 million increase in capacity revenues. In 2016, KWH sales increased 33.3% primarily due to a new contract that became effective in the first quarter 2016 partially offset by a 12.1% decrease in the price of energy due to lower natural gas prices.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clause.

In 2017, wholesale revenues from sales to affiliates increased $28 million, or 40.6%, as compared to the prior year. In 2017, KWH sales increased 31.1% as a result of supporting Southern Company system transmission reliability and a 6.9% increase in the price of energy primarily due to higher natural gas prices. In 2016, wholesale revenues from sales to affiliates decreased $15 million, or 17.9%, as compared to the prior year. In 2016, KWH sales decreased 15.7% as a result of lower-cost generation available in the Southern Company system and a 2.6% decrease in the price of energy primarily due to lower natural gas prices.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2017 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2017	**2017**	2016	**2017**	2016
	(in billions)				
Residential	**17.2**	**(6.1)%**	1.4%	**(1.2)%**	(0.5)%
Commercial	**13.6**	**(3.4)**	(0.1)	**(1.3)**	(0.5)
Industrial	**22.7**	**1.7**	(4.6)	**1.7**	(4.6)
Other	**0.2**	**(5.0)**	3.8	**(5.0)**	3.8
Total retail	**53.7**	**(2.3)**	(1.5)	**(0.1)%**	(2.2)%
Wholesale					
Non-affiliates	**5.5**	**(6.5)**	37.1		
Affiliates	**4.2**	**31.1**	(15.7)		
Total wholesale	**9.7**	**6.6**	12.5		
Total energy sales	**63.4**	**(1.0)%**	0.3%		

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2017 were 2.3% lower than in 2016. Residential sales and commercial sales decreased 6.1% and 3.4% in 2017, respectively, primarily due to milder weather in the first and third quarters 2017 as compared to the corresponding periods in 2016. Weather-adjusted residential sales were 1.2% lower in 2017 primarily due to lower customer usage resulting from an increase in penetration of energy-efficient residential appliances, partially offset by customer growth. Weather-adjusted commercial sales were 1.3% lower in 2017 primarily due to lower customer usage resulting from customer initiatives in energy savings and an ongoing migration to the electronic commerce business model, partially offset by customer growth. Industrial sales increased 1.7% in 2017 as compared to 2016 as a result of an increase in demand resulting from changes in production levels primarily in the primary metals, chemicals, and mining sectors offset by the pipelines and paper sectors.

Retail energy sales in 2016 were 1.5% lower than in 2015. Residential sales increased 1.4% primarily due to warmer weather in the third quarter 2016 as compared to the corresponding period in 2015. Commercial sales remained flat in 2016. Weather-adjusted residential sales were flat in 2016 due to lower customer usage primarily resulting from an increase in efficiency improvements in residential appliances and lighting, partially offset by customer growth. Industrial sales decreased 4.6% in 2016 compared to 2015 as a result of a decrease in demand resulting from changes in production levels primarily in the primary metals, chemical, pipelines, paper, and stone, clay, and glass sectors. A strong dollar, low oil prices, and weak global growth conditions constrained growth in the industrial sector in 2016.

See "Operating Revenues" above for a discussion of significant changes in wholesale revenues from sales to non-affiliates and wholesale revenues from sales to affiliated companies as related to changes in price and KWH sales.

Fuel and Purchased Power Expenses

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

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

	2017	2016	2015
Total generation *(in billions of KWHs)*	**60.3**	60.2	60.9
Total purchased power *(in billions of KWHs)*	**6.4**	7.1	6.3
Sources of generation *(percent)* —			
Coal	**50**	53	54
Nuclear	**24**	23	24
Gas	**20**	19	16
Hydro	**6**	5	6
Cost of fuel, generated *(in cents per net KWH)* —			
Coal	**2.60**	2.75	2.83
Nuclear	**0.75**	0.78	0.81
Gas	**2.72**	2.67	2.94
Average cost of fuel, generated *(in cents per net KWH)*[(a)]	**2.14**	2.26	2.34
Average cost of purchased power *(in cents per net KWH)*[(b)]	**5.29**	4.80	5.66

(a) KWHs generated by hydro are excluded from the average cost of fuel, generated.

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

Fuel and purchased power expenses were $1.55 billion in 2017, a decrease of $78 million, or 4.8%, compared to 2016. The decrease was primarily due to a $67 million net decrease related to the volume of KWHs generated and purchased and a $42 million decrease in the average cost of fuel, partially offset by a $31 million increase in the average cost of purchased power.

Fuel and purchased power expenses were $1.63 billion in 2016, a decrease of $62 million, or 3.7%, compared to 2015. The decrease was primarily due to a $61 million decrease in the average cost of purchased power, and a $59 million decrease in the average cost of fuel, partially offset by a $49 million increase related to the volume of KWHs purchased.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's energy cost recovery clause. The Company, along with the Alabama PSC, continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate ECR" for additional information.

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.

Fuel

Fuel expenses were $1.2 billion in 2017, a decrease of $72 million, or 5.6%, compared to 2016. The decrease was primarily due to a 12.2% increase in the volume of KWHs generated by hydro, a 5.8% decrease in the volume of KWHs generated by coal, and a 5.5% and 3.9% decrease in the average cost of KWHs generated by coal and nuclear fuel, respectively. These decreases were partially offset by an 8.1% increase in the volume of KWHs generated by nuclear fuel and a 4.0% increase in the volume of KWHs generated by natural gas. Fuel expenses were $1.3 billion in 2016, a decrease of $45 million, or 3.4%, compared to 2015. The decrease was primarily due to a 9.2% decrease in the average cost of KWHs generated by natural gas, which excludes tolling agreements, a 4.2% and 3.9% decrease in the volume of KWHs generated by nuclear fuel and coal, respectively, and a 3.7% decrease in the average cost of KWHs generated by nuclear fuel, partially offset by a 17.4% increase in the volume of KWHs generated by natural gas.

Purchased Power – Affiliates

Purchased power expense from affiliates was $158 million in 2017, a decrease of $10 million, or 6.0%, compared to 2016. This decrease was primarily due to a 17.2% decrease in the amount of energy purchased due to milder weather partially offset by a 13.9% increase in the average cost per KWH purchased due to higher natural gas prices. Purchased power expense from affiliates was $168 million in 2016, a decrease of $12 million, or 6.7%, compared to 2015. This decrease was primarily due to a

20.7% decrease in the average cost per KWH purchased due to lower natural gas prices, partially offset by a 17.5% increase in the amount of energy purchased due to the availability of lower-cost generation compared to the Company's owned generation.

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

Other Operations and Maintenance Expenses

In 2017, other operations and maintenance expenses increased $142 million, or 9.4%, as compared to the prior year. Distribution and transmission expenses increased $58 million primarily due to vegetation management expenses. Generation costs increased $38 million primarily due to outage costs. Employee benefit costs, including pension costs, increased $22 million.

In 2016, other operations and maintenance expenses increased $9 million, or 0.6%, as compared to the prior year. Steam production costs increased $28 million primarily due to the timing of generation operating expenses. Transmission and distribution expenses increased $10 million and $7 million, respectively, primarily due to additional vegetation management and other maintenance expenses. These increases were partially offset by a decrease of $32 million in employee benefit costs, including pension costs. The increases in operations and maintenance expenses were primarily Rate CNP compliance-related costs and therefore had no significant impact to net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate CNP Compliance" herein for additional information.

See Note 2 to the financial statements under "Pension Plans" for additional information.

Depreciation and Amortization

Depreciation and amortization increased $33 million, or 4.7%, in 2017 as compared to the prior year primarily due to additional plant in service and an increase in generation-related depreciation rates, effective January 1, 2017, associated with compliance-related steam projects and ARO recovery, partially offset by a decrease in distribution-related depreciation rates. See Note 1 to the financial statements under "Depreciation and Amortization" for additional information. Depreciation and amortization increased $60 million, or 9.3%, in 2016 as compared to the prior year primarily due to compliance-related steam projects placed in service.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $4 million, or 1.1%, in 2017 as compared to the prior year. In 2016, taxes other than income taxes increased $12 million, or 3.3% in 2016 as compared to the prior year. The increase was primarily due to increases in state and municipal utility license tax bases primarily due to an increase in retail revenues. In addition, ad valorem taxes increased primarily due to an increase in assessed value of property.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $11 million, or 39.3%, in 2017 as compared to the prior year. The increase was primarily associated with steam, transmission, and nuclear construction projects. AFUDC equity decreased $32 million, or 53.3%, in 2016 as compared to the prior year. The decrease was primarily associated with steam generation capital projects being placed in service. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $3 million, or 1.0%, in 2017 as compared to the prior year. Interest expense, net of amounts capitalized increased $28 million, or 10.2%, in 2016 as compared to the prior year primarily due to an increase in debt outstanding and a reduction in the amounts capitalized. See FUTURE EARNINGS POTENTIAL – "Financing Activities" herein for additional information.

Other Income (Expense), Net

Other income (expense), net increased $7 million, or 33.3%, in 2017 as compared to the prior year primarily due to increases in unregulated lighting services. Other income (expense), net increased $11 million, or 34.4%, in 2016 as compared to the prior year primarily due to a decrease in donations, partially offset by a decrease in sales of non-utility property.

Income Taxes

Income taxes increased $37 million, or 7.0%, in 2017 as compared to the prior year primarily due to higher pre-tax earnings, an increase in prior year tax return actualization, and an increase in income tax reserves, partially offset by an increase in state income tax credits. The impact to income taxes as a result of Tax Reform Legislation was not material due to the application of regulatory accounting. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 5 to the financial statements for additional information. Income taxes increased $25 million, or 4.9%, in 2016 as compared to the prior year primarily due to higher pre-tax earnings.

Dividends on Preferred and Preference Stock

Dividends on preferred and preference stock increased $1 million, or 5.9%, in 2017 as compared to the prior year. Dividends on preferred and preference stock decreased $9 million, or 34.6%, in 2016 as compared to the prior year. The decrease was primarily due to the redemption in May 2015 of certain series of preferred and preference stock. See Note 6 to the financial statements under "Redeemable Preferred and Preference Stock" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electric service to retail and wholesale customers within its traditional service territory located in the State of Alabama and to wholesale customers in the Southeast. Prices for electric service provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for wholesale electric service, 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 primary business of providing electric service. 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. Future earnings will be impacted by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies and increasing volumes of electronic commerce transactions, both of which could contribute to a net reduction in customer usage. 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 the pace of economic growth that may be affected by changes in regional and global economic conditions, which may impact future earnings.

On December 22, 2017, Tax Reform Legislation was signed into law and became effective on January 1, 2018, which, among other things, reduces the federal corporate income tax rate to 21% and changes rates of depreciation and the business interest deduction. See "Income Tax Matters – Federal Tax Reform Legislation" and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Notes 3 and 5 to the financial statements under "Retail Regulatory Matters – Rate RSE" and "Current and Deferred Income Taxes," respectively, for additional information.

Environmental Matters

The Company's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. The Company maintains a comprehensive environmental compliance strategy to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures and operations and maintenance costs, required to comply with environmental laws and regulations may impact future unit retirement and replacement decisions, results of operations, cash flows, and financial condition. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, and adding or changing fuel sources for certain existing units, as well as related upgrades to the transmission system. A major portion of these compliance costs are expected to be recovered through existing ratemaking provisions. The ultimate impact of the environmental laws and regulations discussed below will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of the Company's operations. The impact of any such changes cannot be determined at this time. Environmental compliance costs could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance costs are recovered through Rate CNP Compliance. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP Compliance" for additional information. Further, increased costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. Additionally, many 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.

Through 2017, the Company has invested approximately $4.7 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $491 million, $260 million, and $349 million for 2017, 2016, and 2015, respectively. Although the timing, requirements, and estimated costs could change as environmental laws and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are initiated or completed, the Company's current compliance strategy estimates capital expenditures of $1.4 billion from 2018 through 2022, with annual totals of approximately $581 million in 2018, $110 million in 2019, $163 million in 2020, $258 million in 2021, and $268 million in 2022. These estimates do not include any potential compliance costs associated with the regulation of CO_2 emissions from fossil fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates expenditures associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

Environmental Laws and Regulations

Air Quality

The EPA has set National Ambient Air Quality Standards (NAAQS) for six air pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and SO_2), which it reviews and revises periodically. Revisions to these standards can require additional emission controls, improvements in control efficiency, or fuel changes which can result in increased compliance and operational costs. NAAQS requirements can also adversely affect the siting of new facilities. In 2015, the EPA published a more stringent eight-hour ozone NAAQS. The EPA plans to complete designations for this rule by no later than April 30, 2018. No areas within the Company's service territory have been or are anticipated to be designated nonattainment under the 2015 ozone NAAQS. In 2010, the EPA revised the NAAQS for SO_2, establishing a new one-hour standard, and is completing designations in multiple phases. The EPA has issued several rounds of area designations and no areas in the vicinity of Company-owned SO_2 sources have been designated nonattainment under the 2010 one-hour SO_2 NAAQS. However, final eight-hour ozone and SO_2 one-hour designations for certain areas are still pending and, if other areas are designated as nonattainment in the future, increased compliance costs could result.

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) and its NO_X annual, NO_X seasonal, and SO_2 annual programs. CSAPR is an emissions trading program that addresses the impacts of the interstate transport of SO_2 and NO_X emissions from fossil fuel-fired power plants located in upwind states in the eastern half of the U.S. on air quality in downwind states. The Company has fossil fuel-fired generation subject to these requirements. In October 2016, the EPA published a final rule that revised the CSAPR seasonal NO_X program, establishing more stringent NO_X emissions budgets in Alabama. Increases in either future fossil fuel-fired generation or the cost of CSAPR allowances could have a negative financial impact on results of operations for the Company.

The EPA finalized regional haze regulations in 2005 and 2017. These regulations require states, tribal governments, and various federal agencies to develop and implement plans to reduce pollutants that impair visibility and demonstrate reasonable progress toward the goal of restoring natural visibility conditions in certain areas, including national parks and wilderness areas. States must submit a revised state implementation plan (SIP) to the EPA by July 31, 2021, demonstrating reasonable progress towards achieving visibility improvement goals. State implementation of reasonable progress could require further reductions in SO_2 or NO_X emissions, which could result in increased compliance costs.

In 2015, the EPA published a final rule requiring certain states (including Alabama) to revise or remove the provisions of their SIPs regulating excess emissions at industrial facilities, including electric generating facilities, during periods of startup, shut-down, or malfunction (SSM). The state excess emission rules provide necessary operational flexibility to affected units during periods of SSM and, if removed, could affect unit availability and result in increased operations and maintenance costs for the Company.

Water Quality

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures at existing power plants and manufacturing facilities in order to minimize their effects on fish and other aquatic life. The regulation requires plant-specific studies to determine applicable measures to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). The ultimate impact of this rule will depend on the outcome of these plant-specific studies and any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule that set national standards for wastewater discharges from steam electric generating units. The rule prohibits effluent discharges of certain wastestreams and imposes stringent arsenic, mercury, selenium, and nitrate/nitrite limits on scrubber wastewater discharges. The revised technology-based limits and compliance dates may require extensive modifications to existing ash and wastewater management systems or the installation and operation of new ash and wastewater management systems. Compliance with the ELG rule is expected to require capital expenditures and increased operational costs primarily affecting the Company's coal-fired electric generation. Compliance applicability dates range from November 1, 2018 to December 31, 2023 with state environmental agencies incorporating specific applicability dates in the NPDES permitting process based on information provided for each waste stream. The EPA has committed to a new rulemaking that could potentially revise the limitations and applicability dates of the ELG rule. The EPA expects to finalize this rulemaking in 2020. The Company continues to monitor the ELG rule and anticipates that approximately 1,000 MWs of the Company's generation will not be available after the compliance date. The ultimate impact of this rule will depend on any new rule-making that revises the limitation and applicable dates. The Company does not anticipate that the unavailability of any units as a result of the ELG rule will have a material impact on the Company's operations or financial condition.

In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) jointly published a final rule that revised the regulatory definition of waters of the United States (WOTUS) for all CWA programs. The rule significantly expanded the scope of federal jurisdiction over waterbodies (such as rivers, streams, and canals), which could impact new generation projects and permitting and reporting requirements associated with the installation, expansion, and maintenance of transmission and distribution projects. On July 27, 2017, the EPA and the Corps proposed to rescind the 2015 WOTUS rule. The WOTUS rule has been stayed by the U.S. Court of Appeals for the Sixth Circuit since late 2015, but on January 22, 2018, the U.S. Supreme Court determined that federal district courts have jurisdiction over the pending challenges to the rule. On February 6, 2018, the EPA and the Corps published a final rule delaying implementation of the 2015 WOTUS rule to 2020.

Coal Combustion Residuals

In 2015, the EPA finalized non-hazardous solid waste regulations for the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments (CCR units) at active generating power plants. The CCR Rule requires CCR units to be evaluated against a set of performance criteria and potentially closed if minimum criteria are not met. Closure of existing CCR units could require installation of equipment and infrastructure to manage CCR in accordance with the rule. The EPA has announced plans to reconsider certain portions of the CCR Rule by no later than December 2019, which could result in changes to deadlines and corrective action requirements.

The EPA's reconsideration of the CCR Rule is due in part to a legislative development that impacts the potential oversight role of state agencies. Under the Water Infrastructure Improvements for the Nation Act, which became law in 2016, states are allowed to establish permit programs for implementing the CCR Rule.

Based on cost estimates for closure in place and monitoring of ash ponds pursuant to the CCR Rule, the Company recorded AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information regarding the Company's AROs as of December 31, 2017.

Global Climate Issues

In 2015, the EPA published final rules limiting CO_2 emissions from new, modified, and reconstructed fossil fuel-fired electric generating units and guidelines for states to develop plans to meet EPA-mandated CO_2 emission performance standards for existing units (known as the Clean Power Plan or CPP). In February 2016, the U.S. Supreme Court granted a stay of the CPP, which will remain in effect through the resolution of litigation in the U.S. Court of Appeals for the District of Columbia challenging the legality of the CPP and any review by the U.S. Supreme Court. On March 28, 2017, the U.S. President signed an executive order directing agencies to review actions that potentially burden the development or use of domestically produced energy resources, including review of the CPP and other CO_2 emissions rules. On October 10, 2017, the EPA published a proposed rule to repeal the CPP and, on December 28, 2017, published an advanced notice of proposed rulemaking regarding a CPP replacement rule.

In 2015, parties to the United Nations Framework Convention on Climate Change, including the United States, adopted the Paris Agreement, which established a non-binding universal framework for addressing greenhouse gas (GHG) emissions based on nationally determined contributions. On June 1, 2017, the U.S. President announced that the United States would withdraw from the Paris Agreement and begin renegotiating its terms. The ultimate impact of this agreement or any renegotiated agreement depends on its implementation by participating countries.

The EPA's GHG reporting rule requires annual reporting of GHG 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 2016 GHG emissions were approximately 38 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2017 GHG emissions on the same basis is approximately 37 million metric tons of CO_2 equivalent.

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 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 and filed their response with the FERC in 2015.

In December 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. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) and Southern Power's compliance filing 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.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies (including the Company) and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

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 Alabama PSC. The Company currently recovers its costs from the regulated retail business primarily through Rate RSE, Rate CNP, Rate ECR, and Rate NDR. In addition, the Alabama PSC issues accounting orders to address current events impacting the Company. See Note 1 to the financial statements and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's rate mechanisms and accounting orders.

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon the Company's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If the Company's actual retail return is above the allowed WCE range, the excess will be refunded to customers unless otherwise directed by the Alabama PSC; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

At December 31, 2016, the Company's retail return exceeded the allowed WCE range which resulted in the Company establishing a $73 million Rate RSE refund liability. In accordance with an Alabama PSC order issued on February 14, 2017, the Company applied the full amount of the refund to reduce the under recovered balance of Rate CNP PPA as discussed further below.

Effective in January 2017, Rate RSE increased 4.48%, or $245 million annually. At December 31, 2017, the Company's actual retail return was within the allowed WCE range. On December 1, 2017, the Company made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2018. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remained unchanged for 2018.

In conjunction with Rate RSE, the Company has an established retail tariff that provides for an adjustment to customer billings to recognize the impact of a change in the statutory income tax rate. As a result of Tax Reform Legislation, the application of this tariff would reduce annual retail revenue by approximately $250 million over the remainder of 2018. The ultimate outcome of this matter cannot be determined at this time.

Rate CNP PPA

The Company's retail rates, approved by the Alabama PSC, provide for adjustments under Rate CNP to recognize the placing of new generating facilities into retail service. The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 7, 2017, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2017 through March 31, 2018. No adjustment to Rate CNP PPA is expected in 2018.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company eliminated the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million. As discussed herein under "Rate RSE," the Company utilized the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and reclassified the remaining $69 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

Rate CNP Compliance

Rate CNP Compliance allows for the recovery of the Company's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. Changes in Rate CNP Compliance-related operations and maintenance expenses and depreciation generally will have no effect on net income.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company reclassified $36 million of its under recovered balance in Rate CNP Compliance to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company leave in effect for 2018 the factors associated with the Company's compliance costs for the year 2017, with any under-collected amount for prior years deemed recovered before any current year amounts. Any under recovered amounts associated with 2018 will be reflected in the 2019 filing.

Rate ECR

The Company has established energy cost recovery rates under the Company's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company reclassified $36 million of its under recovered balance in Rate ECR to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company leave in effect for 2018 the energy cost recovery rates which began in 2017. Therefore, the Rate ECR factor as of January 1, 2018 remained at 2.015 cents per KWH. The rate will return to 5.910 cents per KWH in 2019, absent a further order from the Alabama PSC.

Rate NDR

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. When the reserve balance falls below $50 million, a reserve establishment charge will be activated (and the on-going reserve maintenance charge concurrently suspended) until the reserve balance reaches $75 million. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period.

In December 2017, the reserve maintenance charge was suspended and the reserve establishment charge was activated as a result of the NDR balance falling below $50 million. The Company expects to collect approximately $16 million annually until the reserve balance is restored to $75 million. The NDR balance at December 31, 2017 was $38 million.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

Environmental Accounting Order

Based on an order from the Alabama PSC, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. The regulatory asset will be amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance. See "Environmental Matters – Environmental Laws and Regulations" herein for additional information regarding environmental regulations.

Income Tax Matters

Federal Tax Reform Legislation

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduces the federal corporate income tax rate to 21%, retains normalization provisions for public utility property and existing renewable energy incentives, and repeals the corporate alternative minimum tax.

Regulated utility businesses can continue deducting all business interest expense and are not eligible for bonus depreciation on capital assets acquired and placed in service after September 27, 2017. Projects with binding contracts before September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the Protecting Americans from Tax Hikes (PATH) Act.

In addition, under the Tax Reform Legislation, net operating losses (NOL) generated after December 31, 2017 can no longer be carried back to previous tax years but can be carried forward indefinitely, with utilization limited to 80% of taxable income in the subsequent tax year. The projected reduction of Southern Company's consolidated income tax liability resulting from the tax rate reduction also delays the expected utilization of existing tax credit carryforwards.

For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in an estimated net tax expense of $3 million, a $271 million decrease in regulatory assets, and a $2.0 billion increase in regulatory liabilities, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities.

The Tax Reform Legislation is subject to further interpretation and guidance from the IRS, as well as each respective state's adoption. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC and the Alabama PSC. On January 31, 2018, SCS, on behalf of the traditional electric operating companies (including the Company), filed with the FERC a reduction to the Company's open access transmission tariff charge for 2018 to reflect the revised federal corporate tax rate. See Note 3 to the financial statements under "Regulatory Matters – Rate RSE" for additional information.

See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 5 to the financial statements under "Federal Tax Reform Legislation" for additional information.

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

Bonus Depreciation

Under the Tax Reform Legislation, projects with binding contracts prior to September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the PATH Act. The PATH Act allowed 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. Based on provisional estimates, approximately $200 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year and approximately $90 million for the 2018 tax year. Should Southern Company have a NOL in 2018, all of these cash flows may not be fully realized in 2018. See Note 5 to the financial statements under "Current and Deferred Income Taxes" 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 standards for air, water, land, and protection of other natural resources, 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 or regulatory matters cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Utility Regulation

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

Federal Tax Reform Legislation

Following the enactment of Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Notes 3 and 5 to the financial statements under "Retail Regulatory Matters – Rate RSE" and "Current and Deferred Income Taxes," respectively, for additional information.

Asset Retirement Obligations

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

The liability for AROs primarily relates to the decommissioning of the Company's nuclear facility, Plant Farley, and facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal related to ongoing repair and maintenance, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, asbestos containing material within long-term assets not subject to ongoing repair and maintenance activities, and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

The cost estimates for AROs related to the disposal of CCR are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure in place. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Nuclear Decommissioning" for additional information.

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

Pension and Other Postretirement Benefits

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

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. Beginning in 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 $24 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in an $9 million or less change in total annual benefit expense and a $128 million or less change in projected obligations.

The Company recorded pension costs of $9 million, $11 million, and $48 million in 2017, 2016, and 2015, respectively. Postretirement benefit costs for the Company were $3 million, $4 million, and $5 million in 2017, 2016, and 2015, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and other postretirement benefit costs is capitalized based on construction-related labor charges. Pension and other postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income.

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

Revenue

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), 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 new standard 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.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term, as well as longer-term contractual commitments, including PPAs.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment.

Leases

In February 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 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to cellular towers, railcars, and a PPA where the Company is the lessee and outdoor lighting and to land where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

Other

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2017. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing generation facilities, to comply with environmental regulations including adding environmental modifications to certain 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 2018 through 2020, 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 external securities issuances, borrowings from financial institutions, or equity contributions from Southern Company. The Company plans to use commercial paper to manage seasonal variations in operating cash flows and for other working capital needs. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2017 as compared to December 31, 2016. No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated during 2018. The Company's funding obligations for the nuclear decommissioning trust fund are based on the most recent site study, and the next study is expected to be conducted in 2018. See Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $1.8 billion for 2017, a decrease of $112 million as compared to 2016. The decrease in cash provided from operating activities was primarily due to the timing of income tax payments in 2017 and the receipt of income tax refunds in 2016 as a result of bonus depreciation, partially offset by the voluntary contribution to the qualified pension plan in 2016. Net cash provided from operating activities totaled $1.9 billion for 2016, a decrease of $193 million as compared to 2015. The decrease in cash provided from operating activities was primarily due to the collection of fuel cost recovery revenues and the voluntary contribution to the qualified pension plan, partially offset by the timing of income tax payments and refunds associated with bonus depreciation.

Net cash used for investing activities totaled $1.9 billion for 2017, $1.4 billion for 2016, and $1.5 billion for 2015. These activities were primarily related to gross property additions for environmental, steam generation, distribution, and transmission assets.

Net cash provided from financing activities totaled $163 million in 2017 primarily due to issuances of long-term debt and additional capital contributions from Southern Company, partially offset by the payment of common stock dividends and maturities of long-term debt. Net cash used for financing activities totaled $285 million in 2016 primarily due to the payment of common stock dividends and a redemption of long-term debt, partially offset by issuances of long-term debt and additional capital contributions from Southern Company. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for 2017 included increases of $1.3 billion in property, plant, and equipment primarily due to additions to distribution and transmission facilities and environmental and steam generation assets and $1.1 billion in long-term debt. Other significant changes included an increase of $2.0 billion in deferred credits related to income taxes and decreases of $1.9 billion in accumulated deferred income taxes primarily due to the change in tax rate resulting from Tax Reform Legislation and $0.6 billion in securities due within one year. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 5 to the financial statements for additional information.

The Company's ratio of common equity to total capitalization plus short-term debt was 46.3% and 46.2% at December 31, 2017 and 2016, respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds to meet its future capital needs from sources similar to those used in the past, which were primarily from operating cash flows, external security issuances, borrowings from financial institutions, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

The Company's current liabilities sometimes exceed current assets because of long-term debt maturities and the periodic use of short-term debt as a funding source, as well as significant seasonal fluctuations in cash needs.

At December 31, 2017, the Company had approximately $544 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2017 were as follows:

Expires					Expires Within One Year	
2018	**2020**	**2022**	**Total**	**Unused**	**Term Out**	**No Term Out**
	(in millions)		*(in millions)*		*(in millions)*	
$ 35	$ 500	$ 800	$ 1,335	$ 1,335	$ —	$ 35

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

In May 2017 and September 2017, the Company amended its $800 million and $500 million multi-year credit arrangements, which, among other things, extended the maturity dates from 2020 to 2022 and 2018 to 2020, respectively, as reflected in the table above.

Most of these bank credit arrangements, as well as the Company's term loan arrangements, contain covenants that limit debt levels and contain cross-acceleration provisions to other indebtedness (including guarantee obligations) of the Company. Such cross-acceleration provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017, the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

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

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $854 million as of December 31, 2017. In addition, at December 31, 2017, the Company had $120 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company also has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs. The Company may meet short-term cash needs through its commercial paper program. The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional 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.

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, 2017	**$ 3**	**3.7%**	**$ 25**	**1.3%**	**$ 223**
December 31, 2016	$ —	—%	$ 16	0.6%	$ 200
December 31, 2015	$ —	—%	$ 14	0.2%	$ 100

(*) Average and maximum amounts are based upon daily balances during the 12-month periods ended December 31, 2017, 2016, and 2015.

The Company believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and operating cash flows.

Financing Activities

In February 2017, the Company repaid at maturity $200 million aggregate principal amount of Series 2007A 5.55% Senior Notes.

In March 2017, the Company issued $550 million aggregate principal amount of Series 2017A 2.45% Senior Notes due March 30, 2022. The proceeds were used to repay the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

In August 2017, the Company repaid at maturity $36.1 million aggregate principal amount of Series 1993-A, 1993-B, and 1993-C Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Refunding Bonds (Alabama Power Company Project).

In September 2017, the Company issued 10 million shares ($250 million aggregate stated capital) of 5.00% Class A Preferred Stock, Cumulative, Par Value $1 Per Share (Stated Capital $25 Per Share). The proceeds were used in October 2017 to redeem all 2 million shares ($50 million aggregate stated capital) of 6.50% Series Preference Stock, 6 million shares ($150 million aggregate stated capital) of 6.45% Series Preference Stock, and 1.52 million shares ($38 million aggregate stated capital) of 5.83% Class A Preferred Stock and for other general corporate purposes, including the Company's continuous construction program.

In October 2017, the Company repaid at maturity $325 million aggregate principal amount of Series Q 5.50% Senior Notes.

In November 2017, the Company issued $550 million aggregate principal amount of Series 2017B 3.70% Senior Notes due December 1, 2047. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

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

Credit Rating Risk

At December 31, 2017, 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 Baa2 or below. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, energy price risk management, and transmission.

The maximum potential collateral requirements under these contracts at December 31, 2017 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements	
	(in millions)	
At BBB and/or Baa2	$	1
At BBB- and/or Baa3	$	2
Below BBB- and/or Baa3	$	323

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

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company) from stable to negative.

On January 19, 2018, Moody's revised its rating outlook for the Company from stable to negative.

While it is unclear how the credit rating agencies and regulatory authorities may respond to the Tax Reform Legislation, certain financial metrics, such as the funds from operations to debt percentage, used by the credit rating agencies to assess Southern Company and its subsidiaries, including the Company, may be negatively impacted. Absent actions by Southern Company and its subsidiaries, including the Company, to mitigate the resulting impacts, which, among other alternatives, could include adjusting capital structure and/or monetizing regulatory assets, the Company's credit ratings could be negatively affected. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

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 $1.1 billion of long-term variable interest rate exposure at December 31, 2017 was 2.3%. 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 $11 million at December 31, 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 financial hedge contracts for natural gas purchases. The Company continues to manage a retail fuel-hedging program implemented per the guidelines of the Alabama PSC. The Company had no material change in market risk exposure for the year ended December 31, 2017 when compared to the year ended December 31, 2016.

In addition, Rate ECR allows the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at the Company's electric generating facilities. Rate ECR also allows recovery of the cost of financial instruments used for hedging market price risk up to 75% of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5% of the Company's natural gas budget for that year.

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:

	2017 Changes	2016 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ 12**	$ (54)
Contracts realized or settled	**(1)**	39
Current period changes(*)	**(17)**	27
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (6)**	$ 12

(*) 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:

	2017	2016
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**64**	68
Commodity – Natural gas options	**5**	6
Total hedge volume	**69**	74

The weighted average swap contract cost above market prices was approximately $0.08 per mmBtu as of December 31, 2017 and below market prices was approximately $0.14 per mmBtu as of December 31, 2016. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Substantially all of the natural gas hedge gains and losses are recovered through the Company's retail energy cost recovery clause.

At December 31, 2017 and 2016, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 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 primarily Level 2 of the fair value hierarchy, at December 31, 2017 were as follows:

	Fair Value Measurements December 31, 2017		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	6	4	2
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ 6	$ 4	$ 2

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

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $2.2 billion for 2018, $1.6 billion for 2019, $1.6 billion for 2020, $1.7 billion for 2021, and $1.4 billion for 2022. The construction program includes capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental laws and regulations included in these amounts are $581 million for 2018, $110 million for 2019, $163 million for 2020, $258 million for 2021, and $268 million for 2022. These estimated expenditures do not include any potential compliance costs associated with the regulation of CO_2 emissions from fossil fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure in place 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 million for 2018, $111 million for 2019, $90 million for 2020, $94 million for 2021, and $96 million for 2022. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information. Costs associated with the CCR Rule are expected to be recovered through Rate CNP Compliance.

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

As a result of NRC requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

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

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

Contractual Obligations

Contractual obligations at December 31, 2017 were as follows:

	2018	2019-2020	2021-2022	After 2022	Total
			(in millions)		
Long-term debt[(a)] —					
Principal	$ —	$ 450	$ 1,060	$ 6,176	$ 7,686
Interest	304	598	561	4,408	5,871
Preferred stock dividends[(b)]	15	29	29	—	73
Financial derivative obligations[(c)]	6	4	—	—	10
Operating leases[(d)]	21	40	24	20	105
Capital Lease	1	1	1	2	5
Purchase commitments —					
Capital[(e)]	2,053	2,972	2,914	—	7,939
Fuel[(f)]	974	1,197	459	238	2,868
Purchased power[(g)]	78	171	186	606	1,041
Other[(h)]	47	73	59	313	492
Pension and other postretirement benefit plans[(i)]	19	36	—	—	55
Total	$ 3,518	$ 5,571	$ 5,293	$ 11,763	$ 26,145

(a) All amounts are reflected based on final maturity dates. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of December 31, 2017, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

(c) Includes derivative liabilities related to cash flow hedges of forecasted debt, as well as energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.

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

(e) The Company provides estimated capital expenditures for a 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, 2017, purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" herein for additional information.

(f) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2017.

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy.

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

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

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2017 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, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, 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 and regulations governing air, water, land, and protection of other natural resources, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- the uncertainty surrounding the recently enacted Tax Reform Legislation, including implementing regulations and IRS interpretations, actions that may be taken in response by regulatory authorities, and its impact, if any, on the credit ratings of the Company;
- current and future litigation or 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, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the inherent risks involved in operating nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general;

- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

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STATEMENTS OF INCOME
For the Years Ended December 31, 2017, 2016, and 2015
Alabama Power Company 2017 Annual Report

	2017	2016	2015
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 5,458**	$ 5,322	$ 5,234
Wholesale revenues, non-affiliates	**276**	283	241
Wholesale revenues, affiliates	**97**	69	84
Other revenues	**208**	215	209
Total operating revenues	**6,039**	5,889	5,768
Operating Expenses:			
Fuel	**1,225**	1,297	1,342
Purchased power, non-affiliates	**170**	166	171
Purchased power, affiliates	**158**	168	180
Other operations and maintenance	**1,652**	1,510	1,501
Depreciation and amortization	**736**	703	643
Taxes other than income taxes	**384**	380	368
Total operating expenses	**4,325**	4,224	4,205
Operating Income	**1,714**	1,665	1,563
Other Income and (Expense):			
Allowance for equity funds used during construction	**39**	28	60
Interest expense, net of amounts capitalized	**(305)**	(302)	(274)
Other income (expense), net	**(14)**	(21)	(32)
Total other income and (expense)	**(280)**	(295)	(246)
Earnings Before Income Taxes	**1,434**	1,370	1,317
Income taxes	**568**	531	506
Net Income	**866**	839	811
Dividends on Preferred and Preference Stock	**18**	17	26
Net Income After Dividends on Preferred and Preference Stock	**$ 848**	$ 822	$ 785

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2017, 2016, and 2015
Alabama Power Company 2017 Annual Report

	2017	2016	2015
		(in millions)	
Net Income	**$ 866**	$ 839	$ 811
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(1), $(1), and $(3), respectively	**1**	(2)	(5)
Reclassification adjustment for amounts included in net income, net of tax of $2, $2, and $1, respectively	**3**	4	2
Total other comprehensive income (loss)	**4**	2	(3)
Comprehensive Income	**$ 870**	$ 841	$ 808

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2017, 2016, and 2015
Alabama Power Company 2017 Annual Report

	2017	2016	2015
		(in millions)	
Operating Activities:			
Net income	$ **866**	$ 839	$ 811
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**888**	844	780
Deferred income taxes	**409**	407	388
Allowance for equity funds used during construction	**(39)**	(28)	(60)
Pension and postretirement funding	**(2)**	(133)	—
Other, net	**(14)**	(102)	15
Changes in certain current assets and liabilities —			
-Receivables	**(168)**	94	(160)
-Other current assets	**(16)**	1	40
-Accounts payable	**71**	73	3
-Accrued taxes	**(84)**	93	138
-Retail fuel cost over recovery	**(76)**	(162)	191
-Other current liabilities	**2**	23	(4)
Net cash provided from operating activities	**1,837**	1,949	2,142
Investing Activities:			
Property additions	**(1,882)**	(1,272)	(1,367)
Nuclear decommissioning trust fund purchases	**(237)**	(352)	(439)
Nuclear decommissioning trust fund sales	**237**	351	438
Cost of removal net of salvage	**(112)**	(94)	(71)
Change in construction payables	**161**	(37)	(15)
Other investing activities	**(43)**	(34)	(34)
Net cash used for investing activities	**(1,876)**	(1,438)	(1,488)
Financing Activities:			
Increase in notes payable, net	**3**	—	—
Proceeds —			
Senior notes	**1,100**	400	975
Preferred stock	**250**	—	—
Pollution control revenue bonds	**—**	—	80
Other long-term debt	**—**	45	—
Capital contributions from parent company	**361**	260	22
Redemptions and repurchases —			
Senior notes	**(525)**	(200)	(650)
Preferred and preference stock	**(238)**	—	(412)
Pollution control revenue bonds	**(36)**	—	(134)
Payment of common stock dividends	**(714)**	(765)	(571)
Other financing activities	**(38)**	(25)	(43)
Net cash provided from (used for) financing activities	**163**	(285)	(733)
Net Change in Cash and Cash Equivalents	**124**	226	(79)
Cash and Cash Equivalents at Beginning of Year	**420**	194	273
Cash and Cash Equivalents at End of Year	$ **544**	$ 420	$ 194
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $15, $11, and $22 capitalized, respectively)	$ **285**	$ 277	$ 250
Income taxes (net of refunds)	**236**	(108)	121
Noncash transactions — Accrued property additions at year-end	**245**	84	121

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

BALANCE SHEETS
At December 31, 2017 and 2016
Alabama Power Company 2017 Annual Report

Assets		**2017**		2016
		(in millions)		
Current Assets:				
Cash and cash equivalents	**$**	**544**	$	420
Receivables —				
Customer accounts receivable		**355**		348
Unbilled revenues		**162**		146
Affiliated		**43**		40
Other accounts and notes receivable		**55**		27
Accumulated provision for uncollectible accounts		**(9)**		(10)
Fossil fuel stock		**184**		205
Materials and supplies		**458**		435
Other regulatory assets, current		**124**		149
Other current assets		**90**		45
Total current assets		**2,006**		1,805
Property, Plant, and Equipment:				
In service		**27,326**		26,031
Less: Accumulated provision for depreciation		**9,563**		9,112
Plant in service, net of depreciation		**17,763**		16,919
Nuclear fuel, at amortized cost		**339**		336
Construction work in progress		**908**		491
Total property, plant, and equipment		**19,010**		17,746
Other Property and Investments:				
Equity investments in unconsolidated subsidiaries		**67**		66
Nuclear decommissioning trusts, at fair value		**903**		792
Miscellaneous property and investments		**124**		112
Total other property and investments		**1,094**		970
Deferred Charges and Other Assets:				
Deferred charges related to income taxes		**239**		525
Deferred under recovered regulatory clause revenues		**54**		150
Other regulatory assets, deferred		**1,272**		1,157
Other deferred charges and assets		**189**		163
Total deferred charges and other assets		**1,754**		1,995
Total Assets	**$**	**23,864**	$	22,516

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

BALANCE SHEETS
At December 31, 2017 and 2016
Alabama Power Company 2017 Annual Report

Liabilities and Stockholder's Equity	**2017**	2016
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ —**	$ 561
Accounts payable —		
Affiliated	**327**	297
Other	**585**	433
Customer deposits	**92**	88
Accrued taxes —		
Accrued income taxes	**9**	45
Other accrued taxes	**45**	42
Accrued interest	**77**	78
Accrued compensation	**205**	193
Other regulatory liabilities, current	**1**	85
Other current liabilities	**59**	76
Total current liabilities	**1,400**	1,898
Long-Term Debt (See accompanying statements)	**7,628**	6,535
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,760**	4,654
Deferred credits related to income taxes	**2,082**	65
Accumulated deferred ITCs	**112**	110
Employee benefit obligations	**304**	300
Asset retirement obligations	**1,702**	1,503
Other cost of removal obligations	**609**	684
Other regulatory liabilities, deferred	**84**	100
Other deferred credits and liabilities	**63**	63
Total deferred credits and other liabilities	**7,716**	7,479
Total Liabilities	**16,744**	15,912
Redeemable Preferred Stock (See accompanying statements)	**291**	85
Preference Stock (See accompanying statements)	**—**	196
Common Stockholder's Equity (See accompanying statements)	**6,829**	6,323
Total Liabilities and Stockholder's Equity	**$ 23,864**	$ 22,516
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2017 and 2016
Alabama Power Company 2017 Annual Report

	2017	2016	2017	2016
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (4.44% at 12/31/17) due 2042	**$ 206**	$ 206		
Long-term notes payable —				
5.50% to 5.55% due 2017	**—**	525		
5.125% due 2019	**200**	200		
3.375% due 2020	**250**	250		
2.38% to 3.95% due 2021	**220**	220		
2.45% to 5.875% due 2022	**750**	200		
2.80% to 6.125% due 2023-2047	**4,975**	4,425		
Variable rates (2.55% to 2.786% at 12/31/17) due 2021	**25**	25		
Total long-term notes payable	**6,420**	5,845		
Other long-term debt —				
Pollution control revenue bonds —				
1.625% to 1.85% due 2034	**207**	207		
Variable rates (0.77% to 0.79% at 1/1/17) due 2017	**—**	36		
Variable rates (1.86% to 1.87% at 12/31/17) due 2021	**65**	65		
Variable rates (1.70% to 1.87% at 12/31/17) due 2024-2038	**788**	788		
Total other long-term debt	**1,060**	1,096		
Capitalized lease obligations	**4**	4		
Unamortized debt premium (discount), net	**(11)**	(9)		
Unamortized debt issuance expense	**(51)**	(46)		
Total long-term debt (annual interest requirement — $305 million)	**7,628**	7,096		
Less amount due within one year	**—**	561		
Long-term debt excluding amount due within one year	**7,628**	6,535	**51.7%**	49.7%
Redeemable Preferred Stock:				
Cumulative redeemable preferred stock				
$100 par or stated value — 4.20% to 4.92%				
Authorized — 3,850,000 shares				
Outstanding — 475,115 shares	**48**	48		
$1 par value —				
Authorized — 27,500,000 shares				
Outstanding — 2017: 5.00% — 10,000,000 shares: $25 stated value				
— 2016: 5.83% — 1,520,000 shares: $25 stated value				
(annual dividend requirement — $15 million)	**243**	37		
Total redeemable preferred stock	**291**	85	**2.0**	0.7
Preference Stock:				
$1 par value — 6.45% to 6.50%				
Authorized — 40,000,000 shares				
Outstanding — 2017: no shares				
— 2016: 8,000,000 shares (non-cumulative): $25 stated value	**—**	196	**—**	1.5
Common Stockholder's Equity:				
Common stock, par value $40 per share —				
Authorized — 40,000,000 shares				
Outstanding — 30,537,500 shares	**1,222**	1,222		
Paid-in capital	**2,986**	2,613		
Retained earnings	**2,647**	2,518		
Accumulated other comprehensive loss	**(26)**	(30)		
Total common stockholder's equity	**6,829**	6,323	**46.3**	48.1
Total Capitalization	**$ 14,748**	$ 13,139	**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, 2017, 2016, and 2015
Alabama Power Company 2017 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, 2014	31	$ 1,222	$ 2,304	$ 2,255	$ (29)	$ 5,752
Net income after dividends on preferred and preference stock	—	—	—	785	—	785
Capital contributions from parent company	—	—	37	—	—	37
Other comprehensive income (loss)	—	—	—	—	(3)	(3)
Cash dividends on common stock	—	—	—	(571)	—	(571)
Other	—	—	—	(8)	—	(8)
Balance at December 31, 2015	31	1,222	2,341	2,461	(32)	5,992
Net income after dividends on preferred and preference stock	—	—	—	822	—	822
Capital contributions from parent company	—	—	272	—	—	272
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(765)	—	(765)
Balance at December 31, 2016	**31**	**1,222**	**2,613**	**2,518**	**(30)**	**6,323**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**848**	**—**	**848**
Capital contributions from parent company	**—**	**—**	**373**	**—**	**—**	**373**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**4**	**4**
Cash dividends on common stock	**—**	**—**	**—**	**(714)**	**—**	**(714)**
Other	**—**	**—**	**—**	**(5)**	**—**	**(5)**
Balance at December 31, 2017	**31**	**$ 1,222**	**$ 2,986**	**$ 2,647**	**$ (26)**	**$ 6,829**

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

Alabama 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, 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, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast. Southern Power develops, constructs, acquires, owns, and manages power 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 optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Farley. 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 and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary.

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

Recently Issued Accounting Standards

Revenue

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), 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 new standard 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.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term, as well as longer-term contractual commitments, including PPAs.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment.

Leases

In February 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 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to cellular towers, railcars, and a PPA where the Company is the lessee and outdoor lighting and to land where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

Other

In March 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 and 8 for disclosures impacted by ASU 2016-09.

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

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 $479 million, $460 million, and $438 million during 2017, 2016, and 2015, 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. See Note 7 under "Operating Leases" for information on leases of cellular tower space for the Company's digital wireless communications equipment.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $248 million, $249 million, and $243 million during 2017, 2016, and 2015, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses, which totaled $9 million in 2017, $13 million in 2016, and $11 million in 2015. Mississippi Power also reimbursed the Company for any direct fuel purchases delivered from one of the Company's transfer facilities. There were no such fuel purchases in 2017 and 2016 and $8 million in 2015. See Note 4 for additional information.

The Company has an agreement with Gulf Power under which the Company made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA from a combined cycle plant located in Autauga County, Alabama. Under a related tariff, the Company received $11 million in 2017, $12 million in 2016, and $14 million in 2015 and expects to recover a total of approximately $61 million from 2018 through 2023 from Gulf Power.

In September 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. Transportation costs under this agreement were approximately $9 million in 2017 and $2 million for the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016.

The Company has agreements with PowerSecure for services related to utility infrastructure construction, distributed energy, and energy efficiency projects. Costs for these services amounted to approximately $11 million for 2017 and were immaterial for 2016.

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 2017, 2016, or 2015.

Also, see Note 4 for information regarding the Company's ownership in a PPA and a gas pipeline ownership agreement with SEGCO.

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:

	2017	2016	Note
	(in millions)		
Retiree benefit plans	$ 946	$ 947	(i,j)
Deferred income tax charges	240	526	(a,k,n)
Regulatory clauses	142	—	(m)
Vacation pay	70	69	(c,j)
Loss on reacquired debt	62	68	(b)
Nuclear outage	56	70	(d)
Remaining net book value of retired assets	54	69	(l)
Under/(over) recovered regulatory clause revenues	53	76	(d)
Other regulatory assets	51	50	(f)
Fuel-hedging losses	7	1	(e,j)
Deferred income tax credits	(2,082)	(65)	(a,n)
Other cost of removal obligations	(609)	(684)	(a)
Natural disaster reserve	(38)	(69)	(h)
Asset retirement obligations	(33)	12	(a)
Other regulatory liabilities	(7)	(23)	(e,g)
Total regulatory assets (liabilities), net	$ (1,088)	$ 1,047	

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

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax credits are amortized over the related property lives, which may range up to 50 years. Asset retirement and other cost of removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over the remaining life of the original issue, which may range up to 50 years.

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

(d) Recorded and recovered or amortized as approved or accepted by the Alabama PSC over periods not exceeding 10 years. See Note 3 under "Retail Regulatory Matters" for additional information.

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

(f) Comprised of components including generation site selection/evaluation costs, PPA capacity (to be recovered over the next 12 months), and other miscellaneous assets. Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.

(g) Comprised of components including mine reclamation and remediation liabilities and fuel-hedging gains. Recorded as accepted by the Alabama PSC. Mine reclamation and remediation liabilities will be settled following completion of the related activities.

(h) Utilized as storm restoration and potential reliability-related expenses are incurred, as approved by the Alabama PSC.

(i) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 for additional information.

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

(k) Included in the deferred income tax charges are $13 million for 2017 and $16 million for 2016 for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Alabama PSC, over the average remaining service period which may range up to 15 years.

(l) Recorded and amortized as approved by the Alabama PSC for a period up to 11 years.

(m) Established per an order from the Alabama PSC issued on February 17, 2017 and will be amortized concurrently with the effective date of the Company's next depreciation study. See Note 3 under "Retail Regulatory Matters – Rate RSE" for additional information.

(n) As a result of the Tax Reform Legislation, these accounts include certain deferred income tax assets and liabilities not subject to normalization. The recovery and amortization of these amounts will be established consistent with guidance provided by the Alabama PSC. See Note 5 for additional information.

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

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company and the Alabama PSC continuously monitor the under/over recovered balances. The Company files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters – Rate ECR" and "Retail Regulatory Matters – Rate CNP Compliance" for additional information.

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

Fuel Costs

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

Income and Other Taxes

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

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

Property, Plant, and Equipment

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

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

	2017	2016
	(in millions)	
Generation	**$ 14,213**	$ 13,551
Transmission	**4,119**	3,921
Distribution	**7,034**	6,707
General	**1,948**	1,840
Plant acquisition adjustment	**12**	12
Total plant in service	**$ 27,326**	$ 26,031

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders.

Nuclear Outage Accounting Order

In accordance with an Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over a subsequent 18-month period with the fall outage costs amortization beginning in January of the following year and the spring outage costs amortization beginning in July of the same year.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.9% in 2017, 3% in 2016, and 2.9% in 2015. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC and approved by the FERC. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2016, the Company submitted an updated depreciation study to the FERC and received authorization to use the recommended rates beginning January 2017. The study was also provided to the Alabama PSC.

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

The liability for AROs primarily relates to the decommissioning of the Company's nuclear facility, Plant Farley, and facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015 (CCR Rule), principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal related to ongoing repair and maintenance, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, asbestos containing material within long-term assets not subject to ongoing repair and maintenance activities, and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

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

	2017	2016
	(in millions)	
Balance at beginning of year	**$ 1,533**	$ 1,448
Liabilities incurred	**—**	5
Liabilities settled	**(26)**	(25)
Accretion	**77**	73
Cash flow revisions	**125**	32
Balance at end of year	**$ 1,709**	$ 1,533

The increase in liabilities incurred and cash flow revisions in 2017 is primarily due to updated cost estimates related to the closure of ash ponds and landfills. The increase in 2016 is primarily related to changes in ash pond closure strategy.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2017 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure in place. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Alabama PSC, as well as the IRS. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

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

At December 31, 2017, investment securities in the Funds totaled $902 million, consisting of equity securities of $644 million, debt securities of $223 million, and $35 million of other securities. At December 31, 2016, investment securities in the Funds totaled $790 million, consisting of equity securities of $552 million, debt securities of $208 million, and $30 million of other securities. These amounts exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases.

Sales of the securities held in the Funds resulted in cash proceeds of $237 million, $351 million, and $438 million in 2017, 2016, and 2015, respectively, all of which were reinvested. For 2017, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $125 million, which included $98 million related to unrealized gains on securities held in the Funds at December 31, 2017. For 2016, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $76 million, which included $34 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 $8 million, which included $57 million related to unrealized losses on securities held in the Funds at December 31, 2015. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the Funds through 2040 as approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed a plan with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, the accumulated provisions for decommissioning were as follows:

	2017	2016
	(in millions)	
External trust funds	**$ 902**	$ 790
Internal reserves	**18**	19
Total	**$ 920**	$ 809

Site study cost is the estimate to decommission a facility as of the site study year. The estimated costs of decommissioning as of December 31, 2017 based on the most current study performed in 2013 for Plant Farley are as follows:

Decommissioning periods:	
Beginning year	2037
Completion year	2076
	(in millions)
Site study costs:	
Radiated structures	$ 1,362
Non-radiated structures	80
Total site study costs	$ 1,442

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, the Company's decommissioning costs are based on the site study. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and a trust earnings rate of 7.0%. The next site study is expected to be completed in 2018.

Amounts previously contributed to the Funds are currently projected to be adequate to meet the decommissioning obligations. The Company will continue to provide site-specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with NRC and other applicable requirements.

Allowance for Funds Used During Construction

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. All current construction costs are included in retail rates. The AFUDC composite rate as of December 31 was 8.3% in 2017, 8.4% in 2016, and 8.7% in 2015. AFUDC, net of income taxes, as a percentage of net income after dividends on preferred and preference stock was 5.7% in 2017, 4.2% in 2016, and 9.3% in 2015.

Impairment of Long-Lived Assets and Intangibles

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

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

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

Financial Instruments

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

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017.

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

Comprehensive Income

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

Variable Interest Entities

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

The Company has established a wholly-owned trust to issue preferred securities. See Note 6 under "Long-Term Debt Payable to an Affiliated Trust" for additional information. However, the Company is not considered the primary beneficiary of the trust. Therefore, the investment in the trust is reflected as other investments, and the related loan from the trust is reflected as long-term debt in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2018, no other postretirement trusts contributions are expected.

Actuarial Assumptions

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

Assumptions used to determine net periodic costs:	2017	2016	2015
Pension plans			
Discount rate – benefit obligations	**4.44%**	4.67%	4.18%
Discount rate – interest costs	**3.76**	3.90	4.18
Discount rate – service costs	**4.85**	5.07	4.49
Expected long-term return on plan assets	**7.95**	8.20	8.20
Annual salary increase	**4.46**	4.46	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	**4.27%**	4.51%	4.04%
Discount rate – interest costs	**3.58**	3.69	4.04
Discount rate – service costs	**4.70**	4.96	4.40
Expected long-term return on plan assets	**6.83**	6.83	7.17
Annual salary increase	**4.46**	4.46	3.59

Assumptions used to determine benefit obligations:	2017	2016
Pension plans		
Discount rate	**3.81%**	4.44%
Annual salary increase	**4.46**	4.46
Other postretirement benefit plans		
Discount rate	**3.71%**	4.27%
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 eight 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, 2017 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2026
Post-65 medical	5.00	4.50	2026
Post-65 prescription	10.00	4.50	2026

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, 2017 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 30	$ 26
Service and interest costs	1	1

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.7 billion at December 31, 2017 and $2.4 billion at December 31, 2016. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

	2017	2016
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,663**	$ 2,506
Service cost	**63**	57
Interest cost	**98**	95
Benefits paid	**(120)**	(109)
Actuarial (gain) loss	**294**	114
Balance at end of year	**2,998**	2,663
Change in plan assets		
Fair value of plan assets at beginning of year	**2,517**	2,279
Actual return (loss) on plan assets	**427**	206
Employer contributions	**12**	141
Benefits paid	**(120)**	(109)
Fair value of plan assets at end of year	**2,836**	2,517
Accrued liability	**$ (162)**	$ (146)

At December 31, 2017, the projected benefit obligations for the qualified and non-qualified pension plans were $2.9 billion and $126 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's pension plans consist of the following:

	2017	2016
	(in millions)	
Other regulatory assets, deferred	**$ 890**	$ 870
Other current liabilities	**(12)**	(12)
Employee benefit obligations	**(150)**	(134)

Presented below are the amounts included in regulatory assets at December 31, 2017 and 2016 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 2018.

	2017	2016	Estimated Amortization in 2018
		(in millions)	
Prior service cost	**$ 8**	$ 10	**$ 1**
Net (gain) loss	**882**	860	**54**
Regulatory assets	**$ 890**	$ 870	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2017 and 2016 are presented in the following table:

	2017	2016
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 870**	$ 822
Net (gain) loss	**64**	84
Change in prior service costs	**—**	7
Reclassification adjustments:		
Amortization of prior service costs	**(2)**	(3)
Amortization of net gain (loss)	**(42)**	(40)
Total reclassification adjustments	**(44)**	(43)
Total change	**20**	48
Ending balance	**$ 890**	$ 870

Components of net periodic pension cost were as follows:

	2017	2016	2015
		(in millions)	
Service cost	**$ 63**	$ 57	$ 59
Interest cost	**98**	95	106
Expected return on plan assets	**(196)**	(184)	(178)
Recognized net (gain) loss	**42**	40	55
Net amortization	**2**	3	6
Net periodic pension cost	**$ 9**	$ 11	$ 48

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, 2017, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2018	$ 129
2019	134
2020	139
2021	143
2022	148
2023 to 2027	807

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

	2017	2016
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 501**	$ 505
Service cost	**6**	5
Interest cost	**17**	18
Benefits paid	**(29)**	(28)
Actuarial (gain) loss	**20**	(1)
Retiree drug subsidy	**2**	2
Balance at end of year	**517**	501
Change in plan assets		
Fair value of plan assets at beginning of year	**367**	363
Actual return (loss) on plan assets	**60**	23
Employer contributions	**6**	7
Benefits paid	**(27)**	(26)
Fair value of plan assets at end of year	**406**	367
Accrued liability	**$ (111)**	$ (134)

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's other postretirement benefit plans consist of the following:

	2017	2016
	(in millions)	
Other regulatory assets, deferred	**$ 63**	$ 86
Other regulatory liabilities, deferred	**(7)**	(10)
Employee benefit obligations	**(111)**	(134)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2017 and 2016 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 2018.

	2017	2016	**Estimated Amortization in 2018**
		(in millions)	
Prior service cost	**$ 11**	$ 15	**$ 4**
Net (gain) loss	**45**	61	**1**
Net regulatory assets	**$ 56**	$ 76	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2017 and 2016 are presented in the following table:

	2017	2016
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	**$ 76**	$ 82
Net (gain) loss	**(15)**	—
Reclassification adjustments:		
Amortization of prior service costs	**(4)**	(4)
Amortization of net gain (loss)	**(1)**	(2)
Total reclassification adjustments	**(5)**	(6)
Total change	**(20)**	(6)
Ending balance	**$ 56**	$ 76

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

	2017	2016	2015
		(in millions)	
Service cost	**$ 6**	$ 5	$ 6
Interest cost	**17**	18	20
Expected return on plan assets	**(25)**	(25)	(26)
Net amortization	**5**	6	5
Net periodic postretirement benefit cost	**$ 3**	$ 4	$ 5

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)	
2018	$ 31	$ (2)	$ 29
2019	32	(2)	30
2020	33	(3)	30
2021	34	(3)	31
2022	35	(3)	32
2023 to 2027	173	(14)	159

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, 2017 and 2016, along with the targeted mix of assets for each plan, is presented below:

	Target	**2017**	2016
Pension plan assets:			
Domestic equity	26%	**31%**	29%
International equity	25	**25**	22
Fixed income	23	**24**	29
Special situations	3	**1**	2
Real estate investments	14	**13**	13
Private equity	9	**6**	5
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	42%	**44%**	44%
International equity	22	**22**	20
Domestic fixed income	28	**28**	29
Special situations	1	**—**	1
Real estate investments	4	**4**	4
Private equity	3	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

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, 2017 and 2016. 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, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

	Fair Value Measurements Using				
As of December 31, 2017:	**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(*)	$ 572	$ 276	$ —	$ —	$ 848
International equity(*)	370	333	—	—	703
Fixed income:					
U.S. Treasury, government, and agency bonds	—	200	—	—	200
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	286	—	—	286
Pooled funds	—	155	—	—	155
Cash equivalents and other	51	3	—	—	54
Real estate investments	111	—	—	283	394
Special situations	—	—	—	43	43
Private equity	—	—	—	159	159
Total	$ 1,104	$ 1,255	$ —	$ 485	$ 2,844

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

	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(*)	$ 477	$ 220	$ —	$ —	$ 697
International equity(*)	292	264	—	—	556
Fixed income:					
U.S. Treasury, government, and agency bonds	—	140	—	—	140
Mortgage- and asset-backed securities	—	3	—	—	3
Corporate bonds	—	235	—	—	235
Pooled funds	—	124	—	—	124
Cash equivalents and other	236	1	—	—	237
Real estate investments	74	—	—	274	348
Special situations	—	—	—	43	43
Private equity	—	—	—	130	130
Total	$ 1,079	$ 987	$ —	$ 447	$ 2,513

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

The fair values of other postretirement benefit plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

	Fair Value Measurements Using				
As of December 31, 2017:	**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(*)	$ 52	$ 12	$ —	$ —	$ 64
International equity(*)	16	14	—	—	30
Fixed income:					
U.S. Treasury, government, and agency bonds	—	11	—	—	11
Corporate bonds	—	12	—	—	12
Pooled funds	—	7	—	—	7
Cash equivalents and other	2	—	—	—	2
Trust-owned life insurance	—	253	—	—	253
Real estate investments	5	—	—	12	17
Special situations	—	—	—	2	2
Private equity	—	—	—	7	7
Total	$ 75	$ 309	$ —	$ 21	$ 405

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

	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(*)	$ 51	$ 10	$ —	$ —	$ 61
International equity(*)	13	12	—	—	25
Fixed income:					
U.S. Treasury, government, and agency bonds	—	7	—	—	7
Corporate bonds	—	10	—	—	10
Pooled funds	—	5	—	—	5
Cash equivalents and other	14	—	—	—	14
Trust-owned life insurance	—	220	—	—	220
Real estate investments	4	—	—	12	16
Special situations	—	—	—	2	2
Private equity	—	—	—	6	6
Total	$ 82	$ 264	$ —	$ 20	$ 366

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company matches a portion of the first 6% of employee base salary contributions. The maximum Company match is 5.1% of an employee's base salary. Total matching contributions made to the plan for 2017, 2016, and 2015 were $23 million, $23 million, and $22 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

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

Environmental Matters

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the estimated costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable.

Nuclear Fuel Disposal Costs

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

In 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 2015, the Company recovered approximately $26 million, which was applied to reduce the cost of service for the benefit of customers.

In 2014, the Company filed a lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Farley for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. On October 10, 2017, the Company filed an additional lawsuit against the U.S. government in the Court of Federal Claims for the costs of continuing to store spent nuclear fuel at Plant Farley for the period from January 1, 2015 through December 31, 2017. 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, 2017 for any potential recoveries from the pending lawsuits. The final outcome of these matters cannot be determined at this time. However, the Company expects to credit any recovery back for the benefit of customers in accordance with direction from the Alabama PSC and, therefore, no material impact on the Company's net income is expected.

At Plant Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of the plant.

FERC Matters

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional 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 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 and filed their response with the FERC in 2015.

In December 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. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) and Southern Power's compliance filing 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.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies (including the Company) and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

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

Retail Regulatory Matters

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon the Company's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Retail rates remain unchanged when the WCE ranges between 5.75% and 6.21% with an adjusting point of 5.98% and eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if the Company (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If the Company's actual retail return is above the allowed WCE range, the excess will be refunded to customers unless otherwise directed by the Alabama PSC; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

At December 31, 2016, the Company's retail return exceeded the allowed WCE range which resulted in the Company establishing a $73 million Rate RSE refund liability. In accordance with an Alabama PSC order issued on February 14, 2017, the Company applied the full amount of the refund to reduce the under recovered balance of Rate CNP PPA as discussed further below.

Effective in January 2017, Rate RSE increased 4.48%, or $245 million annually. At December 31, 2017, the Company's actual retail return was within the allowed WCE range. On December 1, 2017, the Company made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2018. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remained unchanged for 2018.

In conjunction with Rate RSE, the Company has an established retail tariff that provides for an adjustment to customer billings to recognize the impact of a change in the statutory income tax rate. As a result of Tax Reform Legislation, the application of this tariff would reduce annual retail revenue by approximately $250 million over the remainder of 2018. The ultimate outcome of this matter cannot be determined at this time.

Rate CNP PPA

The Company's retail rates, approved by the Alabama PSC, provide for adjustments under Rate CNP to recognize the placing of new generating facilities into retail service. The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 7, 2017, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2017 through March 31, 2018. No adjustment to Rate CNP PPA is expected in 2018. As of December 31, 2017 and 2016, the Company had an under recovered Rate CNP PPA balance of $12 million and $142 million, respectively, which is included in deferred under recovered regulatory clause revenues in the balance sheet.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company eliminated the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million. As discussed herein under "Rate RSE," the Company utilized the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and reclassified the remaining $69 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

Rate CNP Compliance

Rate CNP Compliance allows for the recovery of the Company's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. Changes in Rate CNP Compliance-related operations and maintenance expenses and depreciation generally will have no effect on net income.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company reclassified $36 million of its under recovered balance in Rate CNP Compliance to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company leave in effect for 2018 the factors associated with the Company's compliance costs for the year 2017, with any under-collected amount for prior years deemed recovered before any current year amounts. Any under recovered amounts associated with 2018 will be reflected in the 2019 filing. As of December 31, 2017 and 2016, the Company had a deferred under recovered regulatory clause revenues balance of $17 million and $9 million, respectively.

Rate ECR

The Company has established energy cost recovery rates under the Company's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company reclassified $36 million of its under recovered balance in Rate ECR to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company leave in effect for 2018 the energy cost recovery rates which began in 2017. Therefore, the Rate ECR factor as of January 1, 2018 remained at 2.015 cents per KWH. The rate will return to 5.910 cents per KWH in 2019, absent a further order from the Alabama PSC.

At December 31, 2017, the Company's under recovered fuel costs totaled $25 million, which is included in deferred under recovered regulatory clause revenues. At December 31, 2016, the Company had an over recovered fuel balance of $76 million, which was included in other regulatory liabilities, current. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery or return of fuel costs.

Rate NDR

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. When the reserve balance falls below $50 million, a reserve establishment charge will be activated (and the on-going reserve maintenance charge concurrently suspended) until the reserve balance reaches $75 million. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. No such accruals were recorded or designated in any period presented.

In December 2017, the reserve maintenance charge was suspended and the reserve establishment charge was activated as a result of the NDR balance falling below $50 million. The Company expects to collect approximately $16 million annually until the reserve balance is restored to $75 million. The NDR balance at December 31, 2017 was $38 million.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

Environmental Accounting Order

Based on an order from the Alabama PSC, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. The regulatory asset will be amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance.

The Company retired Plant Gorgas Units 6 and 7 (200 MWs) and Plant Barry Unit 3 (225 MWs) in 2015. Additionally, the Company ceased using coal at Plant Barry Units 1 and 2 (250 MWs) in 2015, but such units remain available on a limited basis with natural gas as the fuel source. In April 2016, the Company also ceased using coal at Plant Greene County Units 1 and 2 (300 MWs representing the Company's ownership interest) and began operating Units 1 and 2 solely on natural gas in June 2016 and July 2016, respectively.

In accordance with this accounting order from the Alabama PSC, the Company transferred the unrecovered plant asset balances to regulatory assets at their respective retirement dates. These regulatory assets are being amortized and recovered through Rate CNP Compliance over the units' remaining useful lives, as established prior to the decision for retirement; therefore, these decisions associated with coal operations had no significant impact on the Company's financial statements.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. SEGCO uses natural gas as the primary fuel source for 1,000 MWs of its generating capacity. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and ROE. The Company's share of purchased power totaled $76 million in 2017, $55 million in 2016, and $76 million in 2015 and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

In addition, the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $25 million principal amount of pollution control revenue bonds are outstanding. The Company has guaranteed $100 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. These senior notes mature on December 1, 2018. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guarantee.

At December 31, 2017, the capitalization of SEGCO consisted of $95 million of equity and $125 million of long-term debt on which the annual interest requirement is $4 million. In addition, SEGCO had short-term debt outstanding of $14 million. SEGCO paid $24 million of dividends in 2017 and 2016 compared to an immaterial amount in 2015, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

The Company, which owns and operates a generating unit adjacent to the SEGCO generating units, has a joint ownership agreement with SEGCO for the ownership of an associated gas pipeline. The Company owns 14% of the pipeline with the remaining 86% owned by SEGCO.

In addition to the Company's ownership of SEGCO and joint ownership of an associated gas pipeline, the Company's percentage ownership and investment in jointly-owned generating plants at December 31, 2017 were as follows:

Facility	Total MW Capacity	Company Ownership	Plant in Service	Accumulated Depreciation	Construction Work in Progress
				(in millions)	
Greene County	500	60.00% (1)	$ 172	$ 65	$ 2
Plant Miller					
Units 1 and 2	1,320	91.84% (2)	1,717	619	54

(1) Jointly owned with an affiliate, Mississippi Power.

(2) Jointly owned with PowerSouth Energy Cooperative, Inc.

The Company has contracted to operate and maintain its jointly-owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

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

Federal Tax Reform Legislation

Following the enactment of Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See Note 3 under "Retail Regulatory Matters – Rate RSE" for additional information.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2017	2016	2015
		(in millions)	
Federal —			
Current	**$ 136**	$ 103	$ 110
Deferred	**336**	339	320
	472	442	430
State —			
Current	**23**	20	8
Deferred	**73**	69	68
	96	89	76
Total	**$ 568**	$ 531	$ 506

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:

	2017	2016
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 2,336**	$ 4,307
Property basis differences	**398**	456
Premium on reacquired debt	**16**	26
Employee benefit obligations	**162**	201
Regulatory assets associated with employee benefit obligations	**260**	393
Asset retirement obligations	**220**	289
Regulatory assets associated with asset retirement obligations	**249**	347
Other	**147**	179
Total	**3,788**	6,198
Deferred tax assets —		
Federal effect of state deferred taxes	**143**	266
Unbilled fuel revenue	**22**	36
Storm reserve	**5**	21
Employee benefit obligations	**286**	427
Other comprehensive losses	**10**	19
Asset retirement obligations	**469**	636
Other	**93**	139
Total	**1,028**	1,544
Accumulated deferred income taxes, net	**$ 2,760**	$ 4,654

The implementation of Tax Reform Legislation significantly reduced accumulated deferred income taxes, partially offset by bonus depreciation provisions in the 2015 Protecting Americans from Tax Hikes Act. Tax Reform Legislation also significantly reduced tax-related regulatory assets and increased tax-related regulatory liabilities.

At December 31, 2017, the tax-related regulatory assets to be recovered from customers were $240 million. These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2017, the tax-related regulatory liabilities to be credited to customers were $2.1 billion. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $7 million in 2017 and $8 million annually in 2016 and 2015. At December 31, 2017, the Company had federal ITC carryforwards which are expected to result in $9 million of federal income tax benefits. The federal ITC carryforwards begin expiring in 2038 but are expected to be fully utilized by 2027. The ultimate outcome of these matters cannot be determined at this time.

Tax Credit Carryforwards

The Company had state credit carryforwards for the state of Alabama of approximately $4 million, which begin expiring in 2023 but are expected to be fully utilized.

Effective Tax Rate

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

	2017	2016	2015
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**4.4**	4.2	3.8
Non-deductible book depreciation	**0.9**	1.0	1.2
AFUDC equity	**(1.0)**	(0.7)	(1.6)
Tax Reform Legislation	**0.3**	—	—
Other	**—**	(0.7)	—
Effective income tax rate	**39.6%**	38.8%	38.4%

In March 2016, the FASB issued ASU 2016-09, which changed 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 has no material unrecognized tax benefits for the periods presented. The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial and the Company did not accrue any penalties on uncertain tax positions.

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

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

The Company has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million outstanding as of December 31, 2017 and 2016, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2017 and 2016, trust preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for this trust and the related securities.

Securities Due Within One Year

At December 31, 2017, the Company had no securities due within one year. At December 31, 2016, the Company had $561 million of senior notes and pollution control revenue bonds due within one year.

Maturities through 2022 applicable to total long-term debt are as follows: $200 million in 2019; $250 million in 2020; $310 million in 2021; and $750 million in 2022. There are no scheduled maturities in 2018.

Bank Term Loans

At both December 31, 2017 and 2016, the Company had $45 million of outstanding bank term loan agreements, which are reflected in the statements of capitalization as long-term debt.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of calculating these covenants, any long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. At December 31, 2017, the Company was in compliance with its debt limits.

Pollution Control Revenue Bonds

Pollution control revenue bond obligations represent loans to the Company from public authorities of funds or installment purchases of pollution control and solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred no obligations related to the issuance of pollution control revenue bonds in 2017.

In August 2017, the Company repaid at maturity $36.1 million aggregate principal amount of Series 1993-A, 1993-B, and 1993-C Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Refunding Bonds (Alabama Power Company Project).

The Company had $1.06 billion and $1.10 billion of tax-exempt pollution control revenue bond obligations outstanding at December 31, 2017 and 2016, respectively, including pollution control revenue bonds classified as due within one year.

Senior Notes

In March 2017, the Company issued $550 million aggregate principal amount of Series 2017A 2.45% Senior Notes due March 30, 2022. The proceeds were used to repay the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

In November 2017, the Company issued $550 million aggregate principal amount of Series 2017B 3.70% Senior Notes due December 1, 2047. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

At December 31, 2017 and 2016, the Company had $6.4 billion and $5.8 billion of senior notes outstanding, respectively, including senior notes classified as due within one year. At December 31, 2017 and 2016, the Company did not have any outstanding secured debt.

Redeemable Preferred and Preference Stock

The Company currently has preferred stock, Class A preferred stock, and common stock outstanding. The Company also has authorized preference stock, none of which is outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of the Company contain a feature that allows the holders to elect a majority of the Company's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards.

The Company's preferred stock is subject to redemption at a price equal to the par value plus a premium. The Company's Class A preferred stock is subject to redemption at a price equal to the stated capital. All series of the Company's preferred stock currently are subject to redemption at the option of the Company. The Class A preferred stock is subject to redemption on or after October 1, 2022, or following the occurrence of a rating agency event. Information for each outstanding series is in the table below:

Preferred/Preference Stock	Par Value/ Stated Capital Per Share	Shares Outstanding	Redemption Price Per Share
4.92% Preferred Stock	$100	80,000	$103.23
4.72% Preferred Stock	$100	50,000	$102.18
4.64% Preferred Stock	$100	60,000	$103.14
4.60% Preferred Stock	$100	100,000	$104.20
4.52% Preferred Stock	$100	50,000	$102.93
4.20% Preferred Stock	$100	135,115	$105.00
5.00% Class A Preferred Stock	$25	10,000,000	Stated Capital(*)

(*) Prior to October 1, 2022: $25.50; on or after October 1, 2022: Stated Capital

In September 2017, the Company issued 10 million shares ($250 million aggregate stated capital) of 5.00% Class A Preferred Stock, Cumulative, Par Value $1 Per Share (Stated Capital 25 Per Share). The proceeds were used in October 2017 to redeem all 2 million shares ($50 million aggregate stated capital) of 6.50% Series Preference Stock, 6 million shares ($150 million aggregate stated capital) of 6.45% Series Preference Stock, and 1.52 million shares ($38 million aggregate stated capital) of 5.83% Class A Preferred Stock and for other general corporate purposes, including the Company's continuous construction program.

There were no changes for the year ended December 31, 2016 in redeemable preferred stock or preference stock of the Company.

Dividend Restrictions

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

Bank Credit Arrangements

At December 31, 2017, committed credit arrangements with banks were as follows:

Expires					Expires Within One Year	
2018	2020	2022	Total	Unused	Term Out	No Term Out
	(in millions)		*(in millions)*		*(in millions)*	
$ 35	$ 500	$ 800	$ 1,335	$ 1,335	$ —	$ 35

Most of the bank credit arrangements require payment of a commitment fee based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

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

Most of the Company's bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, any long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. At December 31, 2017, the Company was in compliance with the debt limit covenants.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $854 million as of December 31, 2017. In addition, at December 31, 2017, the Company had $120 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company borrows through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. The Company may also make short-term borrowings through various other arrangements with banks. At December 31, 2017, the Company had $3 million in short-term debt outstanding and none at December 31, 2016. At December 31, 2017, the Company had regulatory approval to have outstanding up to $2.0 billion of short-term borrowings.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2017, 2016, and 2015, the Company incurred fuel expense of $1.2 billion, $1.3 billion, and $1.3 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases. Total capacity expense under PPAs accounted for as operating leases was $41 million, $42 million, and $38 million for 2017, 2016, and 2015, respectively. Total estimated minimum long-term obligations at December 31, 2017 were as follows:

	Operating Lease PPAs
	(in millions)
2018	$ 41
2019	43
2020	44
2021	46
2022	47
2023 and thereafter	—
Total commitments	$ 221

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

Operating Leases

The Company has entered into operating leases with Southern Linc and third parties for the use of cellular tower space. Substantially all of these agreements have initial terms ranging from five to 10 years and renewal options of up to 20 years. The Company has entered into rental agreements for towers, coal railcars, vehicles, and other equipment with various terms and expiration dates. Total rent expense under these agreements was $25 million in 2017, $18 million in 2016, and $19 million in 2015. Of these amounts, $11 million, $14 million, and $13 million for 2017, 2016, and 2015, respectively, relate to the railcar leases and was recovered through the Company's Rate ECR. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2017, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments[a]			
	Affiliate Operating Leases[b]	Railcars	Vehicles & Other	Total
		(in millions)		
2018	$ 8	$ 7	$ 6	$ 21
2019	10	7	5	22
2020	8	7	3	18
2021	7	6	1	14
2022	5	5	—	10
2023 and thereafter	16	4	—	20
Total	$ 54	$ 36	$ 15	$ 105

(a) Minimum lease payments have not been reduced by minimum sublease rentals of $3 million in the future.

(b) Includes operating leases for cellular tower space.

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2023 with maximum obligations under these leases of $12 million in 2023. There are no obligations under these leases through 2022. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

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

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units and restricted stock 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. In 2015 and 2016, stock-based compensation consisted exclusively of performance share units. Beginning in 2017, stock-based compensation granted to employees includes restricted stock units in addition to performance share units. Prior to 2015, stock-based compensation also included stock options. As of December 31, 2017, there were 793 current and former employees participating in the stock option, performance share unit, and restricted stock unit programs.

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.

Southern Company issues performance share units with performance goals based on three performance goals to employees. These include performance share units with performance goals 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, performance share units with performance goals based on Southern Company's 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.

In 2015 and 2016, the EPS-based and ROE-based awards each represented 25% of the total target grant date fair value of the performance share unit awards granted. The remaining 50% of the total target grant date fair value consisted of TSR-based awards. Beginning in 2017, the total target grant date fair value of the stock compensation awards granted was comprised 20% each of EPS-based awards and ROE-based awards and 30% each of TSR-based awards and restricted stock units.

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.

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. Employees become immediately vested in the TSR-based performance share units, along with the EPS-based and ROE-based awards, upon retirement. 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, 2017, 2016, and 2015, employees of the Company were granted performance share units of 135,502, 249,065, and 214,709, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2017, 2016, and 2015, 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 $49.07, $45.15, and $46.42, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017, 2016, and 2015 was $49.21, $48.86, and $47.78, respectively.

For the years ended December 31, 2017, 2016, and 2015, total compensation cost for performance share units recognized in income was $9 million, $15 million, and $13 million, respectively, with the related tax benefit also recognized in income of $4 million, $6 million, and $5 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, 2017, $2 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 21 months.

Restricted Stock Units

Beginning in 2017, stock-based compensation granted to employees included restricted stock units in addition to performance share units. One-third of the restricted stock units granted to employees vest each year throughout a three-year service period. All unvested restricted stock 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 vesting period.

The fair value of restricted stock units is based on the closing stock price of Southern Company common stock on the date of the grant. Since one-third of the restricted stock units vest each year throughout a three-year service period, compensation expense for restricted stock unit awards is generally recognized over the corresponding one-, two-, or three-year period. Employees become immediately vested in the restricted stock units upon retirement. 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.

For the year ended December 31, 2017, employees of the Company were granted 58,001 restricted stock units. The weighted average grant-date fair value of restricted stock units granted during 2017 was $49.21.

For the year ended December 31, 2017, total compensation cost for restricted stock units recognized in income was $3 million with the related tax benefit also recognized in income of $1 million. As of December 31, 2017, total unrecognized compensation cost related to restricted stock units was immaterial.

Stock Options

In 2015, Southern Company discontinued the granting of stock options. Stock options expire no later than 10 years after the grant date and the latest possible exercise will occur no later than November 2024.

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, 2017, all compensation cost related to stock option awards has been recognized.
The total intrinsic value of options exercised during the years ended December 31, 2017, 2016, and 2015 was $12 million, $21 million, and $8 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 $5 million, $8 million, and $3 million for the years ended December 31, 2017, 2016, and 2015, respectively. Prior to the adoption of ASU 2016-09 in 2016, 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, 2017, the aggregate intrinsic value for the options outstanding and exercisable was $17 million.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $450 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $255 million per incident but not more than an aggregate of $38 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses and policies 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. The Company purchases limits based on the projected full cost of replacement power and has elected a 12-week deductible waiting period.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for the Company as of December 31, 2017 under the NEIL policies would be $55 million.

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

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

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

10. FAIR VALUE MEASUREMENTS

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

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- 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, 2017, 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, 2017:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Energy-related derivatives	$ —	$ 4	$ —	$ —	$ 4
Nuclear decommissioning trusts:(*)					
Domestic equity	442	81	—	—	523
Foreign equity	62	59	—	—	121
U.S. Treasury and government agency securities	—	24	—	—	24
Corporate bonds	21	160	—	—	181
Mortgage and asset backed securities	—	18	—	—	18
Private equity	—	—	—	29	29
Other	6	—	—	—	6
Cash equivalents	349	—	—	—	349
Total	$ 880	$ 346	$ —	$ 29	$ 1,255
Liabilities:					
Energy-related derivatives	$ —	$ 10	$ —	$ —	$ 10

(*) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases. See Note 1 under "Nuclear Decommissioning" for additional information.

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)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Energy-related derivatives	$ —	$ 20	$ —	$ —	$ 20
Nuclear decommissioning trusts:(*)					
Domestic equity	385	72	—	—	457
Foreign equity	48	47	—	—	95
U.S. Treasury and government agency securities	—	21	—	—	21
Corporate bonds	22	146	—	—	168
Mortgage and asset backed securities	—	19	—	—	19
Private equity	—	—	—	20	20
Other	—	10	—	—	10
Cash equivalents	262	—	—	—	262
Total	$ 717	$ 335	$ —	$ 20	$ 1,072
Liabilities:					
Energy-related derivatives	$ —	$ 9	$ —	$ —	$ 9

(*) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives 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. See Note 1 under "Nuclear Decommissioning" for additional information. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available.

As of December 31, 2017 and 2016, the fair value measurements of private equity investments held in the nuclear decommissioning trusts that are calculated at net asset value per share (or its equivalent) as a practical expedient, as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
As of December 31, 2017	**$ 29**	**$ 21**	**Not Applicable**	**Not Applicable**
As of December 31, 2016	$ 20	$ 25	Not Applicable	Not Applicable

Private equity funds include a fund-of-funds that invests in high quality private equity funds across several market sectors, funds that invest in real estate assets, and a fund that acquires companies to create resale value. Private equity funds do not have redemption rights. Distributions from these funds will be received as the underlying investments in the funds are liquidated. Liquidations of these investments are expected to occur at various times over the next 10 years.

As of December 31, 2017 and 2016, 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:		
2017	**$ 7,625**	**$ 8,305**
2016	$ 7,092	$ 7,544

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

11. DERIVATIVES

The Company is exposed to market risks, including 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 fuel-hedging programs, implemented per the guidelines of the Alabama PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

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

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

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

At December 31, 2017, the net volume of energy-related derivative contracts for natural gas positions totaled 69 million mmBtu for the Company, with the longest hedge date of 2020 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

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 5 million mmBtu.

Interest Rate Derivatives

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

At December 31, 2017, there were no interest rate derivatives outstanding.

The estimated pre-tax losses related to interest rate derivatives that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2018 are $6 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

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. 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, 2017 and 2016, the fair value of energy-related derivatives was reflected on the balance sheets as follows:

	2017		2016	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	Assets	Liabilities
		(in millions)		
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 2**	**$ 6**	$ 13	$ 5
Other deferred charges and assets/Other deferred credits and liabilities	**2**	**4**	7	4
Total derivatives designated as hedging instruments for regulatory purposes	**$ 4**	**$ 10**	$ 20	$ 9
Gross amounts recognized	**$ 4**	**$ 10**	$ 20	$ 9
Gross amounts offset	**$ (4)**	**$ (4)**	$ (8)	$ (8)
Net amounts recognized in the Balance Sheets	**$ —**	**$ 6**	$ 12	$ 1

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2017 and 2016.

At December 31, 2017 and 2016, the pre-tax effect 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**	**2017**	2016	**Balance Sheet Location**	**2017**	2016
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (4)**	$ (1)	Other regulatory liabilities, current	**$ 1**	$ 8
	Other regulatory assets, deferred	**(3)**	—	Other regulatory liabilities, deferred	**—**	4
Total energy-related derivative gains (losses)		**$ (7)**	$ (1)		**$ 1**	$ 12

For the years ended December 31, 2017, 2016, and 2015, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2017**	2016	2015	**Statements of Income Location**	**2017**	2016	2015
	(in millions)				*(in millions)*		
Interest rate derivatives	**$ —**	$ (3)	$ (7)	Interest expense, net of amounts capitalized	**$ (6)**	$ (6)	$ (3)

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 not material for any year presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies.

At December 31, 2017, the fair value of derivative liabilities with contingent features was $1 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk related contingent features, at a rating below BBB- and/or Baa3, were $12 million, and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

The Company maintains accounts with certain regional transmission organizations to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, the Company may be required to post collateral. At December 31, 2017, the Company's collateral posted in these accounts was not material.

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 2017 and 2016 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2017	**$ 1,382**	**$ 376**	**$ 174**
June 2017	**1,484**	**454**	**230**
September 2017	**1,740**	**616**	**325**
December 2017	**1,433**	**268**	**119**
March 2016	$ 1,331	$ 333	$ 156
June 2016	1,444	430	213
September 2016	1,785	650	351
December 2016	1,329	252	102

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

	2017	2016	2015	2014	2013
Operating Revenues (in millions)	**$ 6,039**	$ 5,889	$ 5,768	$ 5,942	$ 5,618
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 848**	$ 822	$ 785	$ 761	$ 712
Cash Dividends on Common Stock (in millions)	**$ 714**	$ 765	$ 571	$ 550	$ 644
Return on Average Common Equity (percent)	**12.89**	13.34	13.37	13.52	13.07
Total Assets (in millions)[(a)(b)]	**$ 23,864**	$ 22,516	$ 21,721	$ 20,493	$ 19,185
Gross Property Additions (in millions)	**$ 1,949**	$ 1,338	$ 1,492	$ 1,543	$ 1,204
Capitalization (in millions):					
Common stock equity	**$ 6,829**	$ 6,323	$ 5,992	$ 5,752	$ 5,502
Preference stock	**—**	196	196	343	343
Redeemable preferred stock	**291**	85	85	342	342
Long-term debt[(a)]	**7,628**	6,535	6,654	6,137	6,195
Total (excluding amounts due within one year)	**$ 14,748**	$ 13,139	$ 12,927	$ 12,574	$ 12,382
Capitalization Ratios (percent):					
Common stock equity	**46.3**	48.1	46.4	45.8	44.4
Preference stock	**—**	1.5	1.5	2.7	2.8
Redeemable preferred stock	**2.0**	0.7	0.7	2.7	2.7
Long-term debt[(a)]	**51.7**	49.7	51.4	48.8	50.1
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**1,268,271**	1,262,752	1,253,875	1,247,061	1,241,998
Commercial	**199,840**	199,146	197,920	197,082	196,209
Industrial	**6,171**	6,090	6,056	6,032	5,851
Other	**766**	762	757	753	751
Total	**1,475,048**	1,468,750	1,458,608	1,450,928	1,444,809
Employees (year-end)	**6,613**	6,805	6,986	6,935	6,896

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $40 million and $38 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $20 million and $27 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

SELECTED FINANCIAL AND OPERATING DATA 2013-2017 (continued)
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	2017	2016	2015	2014	2013
Operating Revenues (in millions):					
Residential	**$ 2,302**	$ 2,322	$ 2,207	$ 2,209	$ 2,079
Commercial	**1,649**	1,627	1,564	1,533	1,477
Industrial	**1,477**	1,416	1,436	1,480	1,369
Other	**30**	(43)	27	27	27
Total retail	**5,458**	5,322	5,234	5,249	4,952
Wholesale — non-affiliates	**276**	283	241	281	248
Wholesale — affiliates	**97**	69	84	189	212
Total revenues from sales of electricity	**5,831**	5,674	5,559	5,719	5,412
Other revenues	**208**	215	209	223	206
Total	**$ 6,039**	$ 5,889	$ 5,768	$ 5,942	$ 5,618
Kilowatt-Hour Sales (in millions):					
Residential	**17,219**	18,343	18,082	18,726	17,920
Commercial	**13,606**	14,091	14,102	14,118	13,892
Industrial	**22,687**	22,310	23,380	23,799	22,904
Other	**198**	208	201	211	211
Total retail	**53,710**	54,952	55,765	56,854	54,927
Wholesale — non-affiliates	**5,415**	5,744	3,567	3,588	3,711
Wholesale — affiliates	**4,166**	3,177	4,515	6,713	7,672
Total	**63,291**	63,873	63,847	67,155	66,310
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**13.37**	12.66	12.21	11.80	11.60
Commercial	**12.12**	11.55	11.09	10.86	10.63
Industrial	**6.51**	6.35	6.14	6.22	5.98
Total retail	**10.16**	9.68	9.39	9.23	9.02
Wholesale	**3.89**	3.95	4.02	4.56	4.04
Total sales	**9.21**	8.88	8.71	8.52	8.16
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,601**	14,568	14,454	15,051	14,451
Residential Average Annual Revenue Per Customer	**$ 1,819**	$ 1,844	$ 1,764	$ 1,775	$ 1,676
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**11,797**	11,797	11,797	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	**10,513**	10,282	12,162	11,761	9,347
Summer	**10,711**	10,932	11,292	11,054	10,692
Annual Load Factor (percent)	**63.5**	63.5	58.4	61.4	64.9
Plant Availability (percent):					
Fossil-steam	**82.8**	83.0	81.5	82.5	87.3
Nuclear	**97.6**	88.0	92.1	93.3	90.7
Source of Energy Supply (percent):					
Coal	**44.8**	47.1	49.1	49.0	50.0
Nuclear	**22.2**	20.3	21.3	20.7	20.3
Hydro	**5.4**	4.8	5.6	5.5	8.1
Gas	**18.1**	17.1	14.6	15.4	15.7
Purchased power —					
From non-affiliates	**4.6**	4.8	4.4	3.6	2.9
From affiliates	**4.9**	5.9	5.0	5.8	3.0
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Alabama Power Company 2017 Annual Report

Directors

Whit Armstrong
Managing Member,
Creeke Capital Investments, LLC

David J. Cooper, Sr.[1]
Vice Chairman,
Cooper/T. Smith Corporation

Mark A. Crosswhite
Chairman, President, and CEO,
Alabama Power Company

O.B. Grayson Hall, Jr.
Chairman and CEO,
Regions Financial Corporation

Anthony A. Joseph
Shareholder,
Maynard, Cooper & Gale, P.C.

Patricia M. King[1]
Chairman,
Sunny King Automotive Group

James K. Lowder
Chairman,
The Colonial Company

Robert D. Powers
President,
The Eufaula Agency, Inc.

Catherine J. Randall
Chairman,
Pettus Randall Holdings, LLC

C. Dowd Ritter
Retired Chairman and CEO,
Regions Financial Corporation

R. Mitchell Shackleford III
President,
Canfor Southern Pine

Officers

Mark A. Crosswhite
Chairman, President, and CEO

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer

Gregory J. Barker
Executive Vice President

Zeke W. Smith
Executive Vice President

Alexia B. Borden[2]
Senior Vice President
and General Counsel

Matthew W. Bowden[3]
Senior Vice President and General Counsel

James P. Heilbron
Senior Vice President and Senior Production Officer

John O. Hudson III
Senior Vice President

Gordon G. Martin
Senior Vice President

R. Scott Moore[4]
Senior Vice President

Quentin P. Riggins
Senior Vice President

Anita Allcorn-Walker
Vice President and Comptroller

Ronald Q. Patterson
Vice President and Assistant Treasurer

Myla E. Calhoun
Vice President

Susan B. Comensky
Vice President

Stephanie K. Cooper
Vice President

Mark S. Crews
Vice President

J. Leigh Davis
Vice President

Daniel K. Glover[5]
Vice President

R. Myrk Harkins[5]
Vice President

Richard O. Hutto
Vice President

Patrick T. Murphy, Jr.
Vice President

Kenneth F. Novak
Vice President

J. Jeffrey Peoples
Vice President

Jonathan K. Porter
Vice President

Ashley N. Robinett
Vice President

Leslie L. Sanders
Vice President

R. Michael Saxon
Vice President

Don A. Scivley
Vice President

Julia H. Segars[5]
Vice President

J. Houston Smith, III[6]
Vice President

Anthony A. Smoke
Vice President

Robert L. Weaver[7]
Vice President

Ceila H. Shorts
Corporate Secretary

Wendy M. Hoomes
Assistant Comptroller

Melissa K. Caen
Assistant Secretary and
Assistant Treasurer

Amy E. Blankenship
Assistant Secretary

Kimberly L. Jackson
Assistant Secretary

Christopher R. Blake
Assistant Treasurer

Brian E. George
Assistant Treasurer

[1] Retiring effective 4/2018
[2] Elected effective 11/2017 (previously served as Vice President)
[3] Deceased 10/2017
[4] Elected effective 5/2017 (previously served as Vice President)
[5] Retired effective 7/2017
[6] Elected effective 11/2017
[7] Resigned effective 4/2017

CORPORATE INFORMATION
Alabama Power Company 2017 Annual Report

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 and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast. The Company provides electric service to more than 1.4 million customers. In 2017, retail energy sales accounted for 85% percent of the Company's total sales of 63 billion kilowatt-hours.

The Company is a wholly-owned subsidiary of The Southern Company, which is the parent company of four traditional electric operating companies, Southern Power Company, and Southern Company Gas. There is no established public trading market for the Company's common stock.

Trustee, Registrar, and Paying Agent
All series of Senior Notes and Trust Preferred Securities
Regions Bank
Corporate Trust
1900 5th Avenue North, 25th Floor
Birmingham, AL 35203

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

shareowneronline.com

Number of Preferred Shareholders of record as of December 31, 2017 was 1,145.

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	2017	2016
	(in thousands)	
First	$178,507	$191,206
Second	178,507	191,206
Third	178,507	191,206
Fourth	178,507	191,206

Form 10-K
A copy of the Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary. For additional information, contact the office of the Corporate Secretary at (205) 257-1000.

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